DETERMINING RESERVES IN LOW PERMEABILITY AND LAYERED RESERVOIRS USING THE MINIMUM TERMINAL DECLINE RATE METHOD: HOW GOOD ARE THE PREDICTIONS?

A Thesis

by

MARCIA DONNA McMILLAN

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2011

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	John Lee
Committee Members,	Duane McVay
	Yuefeng Sun
Head of Department,	Stephen Holditch

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ABSTRACT

Determining Reserves in Low Permeability and Layered Reservoirs Using the Minimum Terminal Decline Rate Method: How Good are the Predictions? (May 2011)

Marcia Donna McMillan, B.S., Pennsylvania State University

Chair of Advisory Committee: Dr. John Lee

This thesis evaluates the applicability of forecasting production from low permeability and layered tight gas wells using the Arps hyperbolic equation at earlier times and then switching to the exponential form of the equation at a predetermined minimum decline rate. This methodology is called the minimum terminal decline rate method.

Two separate completion types have been analyzed. The first is horizontal completions with multi-stage hydraulic fractures while the second is vertical fractured wells in layered formations, completed with hydraulic fractures. For both completion types both simulated data and real world well performance histories have been evaluated using differing minimum terminal decline rates and the benefit of increasing portions of production history to make predictions.

The application of the minimum terminal decline rate method to the simulated data in this study (3% minimum decline applied to multiple fractured horizontal wells – MFHW- and 7% applied to vertical fractured layered wells) gave high errors for some simulations within the first two years. Once additional production data is considered in making predictions, the errors in estimated ultimate recovery and in remaining reserves is

significantly reduced. This result provides a note of caution, when using the minimum decline rate method for forecasting using small quantities of production history.

The evaluation of real world data using the minimum terminal decline rate method introduces other inaccuracies such as poor data quality, low data frequency, operational changes which affect the production profile and workovers / re-stimulations which require a restart of production forecasting process.

Real well data for MFHW comes from the Barnett Shale completions of the type which have been widely utilized since 2004. There is insufficient production history from real wells to determine an appropriate minimum terminal decline rate. In the absence of suitable analogs for the determination of the minimum terminal decline rate it would be impossible to correctly apply this methodology.

Real well data for vertical fractured layered wells from the Carthage Cotton Valley field indicate that for wells similar to Conoco operated Panola County wells a feasible decline rate is between 5% and 10%. Further if a consistent production trend and with more than 2 years of production history are used to forecast, the EUR can be predicted to within +/- 10 % and remaining reserves to within +/- 15%.

DEDICATION

I would like to dedicate this thesis to my parents and siblings who have always given strength to achieve my goals.

ACKNOWLEDGEMENTS

I would like to express my gratitude and respect to my advisor, Dr. John Lee for his support and advice throughout this process. I would also like to thank the other members of my committee Dr. McVay and Dr. Sun for providing direction. Special thanks as well to Ms. Eleanor Schuler and Dr. Mamora for their support through trying times and to Hamid Rahnema. Finally, I would also like to thank my friends, colleagues and the departments' staff for making my time at Texas A&M a great experience.

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I. INTRODUCTION

1.1 The Importance of This Research

The correct prediction of Estimated Ultimate Recovery (EUR) and Remaining Reserves (RR) from an existing well is extremely important in the oil and gas industry because of the impact on a company's financial bottom line.

One method that is widely used for forecasting and for determining reserves is the minimum terminal decline rate method. In this method the Arps hyperbolic model, is used at earlier times and then switched to the exponential form of the equation at a predetermined minimum decline rate, a method first introduced by Long and Davis. (Long and Davis 1988)

The Arps exponential model has been rigorously proven for incompressible fluid in boundary dominated flow (Fetkovich et al. 1996) and even in these cases, several other conditions must be met for accurate application of method. These include that the well must be producing at a constant bottom-hole pressure, with a constant productivity index and a constant drainage radius for the life of the forecast. Strictly speaking, if the considerations are not satisfied the forecast may not be valid.

The completion types investigated in this study are horizontal wells with multiple fractures (MFHW) drilled in shale gas formations and vertical fractured layered wells in tight gas formations both of which are of economic importance in to US gas industry.

This thesis follows the style of *Society of Petroleum Engineers.*

The application of this methodology for MFHW in tight gas formations is at best approximate since typically the boundary dominated flow is not achieved during the life of the well and the result of fitting historical production data with the hyperbolic equation is a high Arps b value which is continuously decreasing. Values of b greater than 1 indicate transience (Fetkovich et al. 1996), and the resulting predicted cumulative production goes to infinity (Valko 2009), necessitating the imposition of the conservative exponential model. The exponential tail constrains the reserves (EUR and RR) and curtails the life of the well. The premise of the minimum terminal decline method is that the Arps over-prediction is fixed by the exponential model under-prediction.

Similarly the application of the minimum terminal decline rate to layered reservoirs introduces other inaccuracies since different flow regimes can coexist in different layers affecting the decline characteristics of the well (Cheng et al. 2008).

Nonetheless the minimum terminal decline rate method is still applied, perhaps due to the ease of application, for making predictions regarding these reservoirs. Considering that neither production from low permeability gas reservoirs or for layered gas reservoirs can be rigorously forecasted using the Arps Models, the question arises: Are the prediction made using this method any good? How can an appropriate minimum terminal decline rate be determined for each reservoir type? Are the projections made using more recently developed methods better?

This thesis reports the findings from analyzing simulated data as well as real well data using the minimum terminal decline rate, for two aforementioned completion types.

Real wells data for the MFHW is taken from the Barnett Shale while real well data for the Vertical Fractured Layered well is taken from the Carthage Cotton Valley field. This analysis involves using a range of minimum terminal decline rates applied with the benefit of increasing quantities of production history. In all cases the relative percentage errors in Estimated Ultimate Recovery and Remaining Reserves are assessed, in so doing:

1. Providing an understanding of the applicability of the process for assessing a particular completion type.

2. Providing an indication of which minimum terminal decline rate gives the closest approximation to the known result for the well being analyzed. If the applied decline rate is too high the tendency is the drastically underestimate production rates and reserves. The converse is also true if the decline rate applied is too low.

Here is it prudent to note that Remaining Reserves is more important factor in determining the applicability of the process since EUR values are heavily influenced by the high initial production rates from tight gas formations. The real question is or should be, how much more is there left to produce from this well and at what rate can it be produced. It is these questions that most affect the financial bottom line and as such specific attention is paid to finding the error in remaining reserves.

One should always bear in mind that these predictions, apply only to wells which are not re-stimulated or had other well interventions that significantly alter the production profile as this invalidates the analysis.

Additionally, the work done in this study includes only the evaluation of single wells. No work has been done in this study on groups of wells. Wells drilled at different times would have to be adjusted to a single starting point prior to analysis or the resulting evaluation would be invalid. Given the large number of wells typically drilled in tight gas and shale formations and the frequency with which these wells are worked over, these are factors which should always be considered before applying this method.

1.2 What Exactly Is the Minimum Terminal Decline Rate Method?

The minimum terminal decline rate method is a decline curve forecasting methodology which starts with the Arps Hyperbolic model, and then, at a predetermined decline rate switches to the Arps Exponential model.

The Arps Hyperbolic Model is given by the following equation

$$q_t = q_i (1 + bD_i t)^{-1/b} \quad \text{......1}$$

Where

q_i Initial stabilized rate

b Arps hyperbolic parameter theoretically between 0 and 1.

D_i Initial decline rate of the function

The decline rate at any time can be calculated using

$$D = \frac{-\Delta q / q}{\Delta t} \quad \text{......2}$$

If the predetermined exponential decline is D_{exp}, then the time at which the forecast switches from hyperbolic to exponential can be calculated using:

$$t_{switch} = \left(\frac{D_i}{D_{exp}} - 1 \right) \Big/ bD_i \quad \text{......3}$$

The rate at which one switches to exponential can be calculated using the Arps hyperbolic parameters and substituting t_{switch} for time (t) in the Arps hyperbolic rate time equation listed as equation 1 above. Once the rate at which the forecast switches to exponential function q_{h-e}, has been determined the Arps exponential function is applied until the abandonment rate or economic limit of the well has been reached.

The Arps exponential rate –time function can be calculated using

$$q_{t\exp} = q_{h-e} e^{-D_{\exp}(t - tswitch)} \quad \ldots\ldots\ldots 4$$

If the decline rate of the well has already declined beneath the predetermined decline rate D_{exp}, then the switch to the exponential forecast occurs immediately at the start of the forecast period and the current decline rate of the well is held until the end of the predicted well life.

II. HORIZONTAL WELLS WITH MULTIPLE FRACTURES

2.1 Base Case for Simulated Horizontal Wells with Multiple Fractures

The objective of this study was to determine whether or not the minimum terminal decline curve method of production forecasting is appropriate for application in shale gas reservoirs and in layered tight gas reservoirs. Furthermore, which minimum decline rate should be applied? This section deals with the first of two completion types- horizontal wells with multiple fractures (MFHW).

To determine whether or not minimum decline is applicable, a systematic study was first undertaken using synthetic data and then followed by the analysis of real well data. For the systematic study we first start with a base case generated by an analytical Topaz model (Ecrin). Complete production histories of 30 years were simulated for unbounded horizontal wells with multiple fractures, with well and reservoir properties informed by the published work of Cipolla (Cipolla 2009) on the Barnett shale formations. This well represents the typical completion type which began to be widely applied in the Barnett Shale reservoir after 2004. The major differences relate to perfecting horizontal drilling and multistage completion techniques in the shale formations. Table 1 below lists the specific well and reservoir properties simulated for the MFHW base case while Figure 1 below is the two dimensional overhead view, from Topaz, of the horizontal well completion.

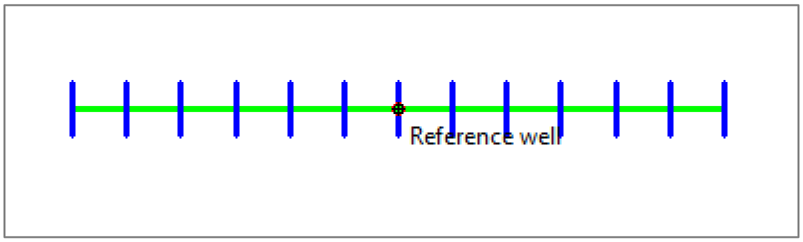

Figure 1: Plan view of the horizontal multi-fractured well. The green represents the horizontal well (toe to heel) and the blue lines which cross the well perpendicularly represent the fractures. Thus this illustrates a horizontal well with 13 equally spaced fractures.

The generated base case had a cumulative production of 2.455 BCF at the end of 30 years of production. For this case and for each simulated profile the decline rate has been calculated throughout the life of the well. Typical production rates and declines rates are quite high but decrease quickly. Decline rate of 5% per year are noted as early as in the 9^{th} year. Decline rate at the 20^{th} year is 2.731% and at the production at 30 years the decline rate is 1.8%

Subsequent to the calculation of the decline rates, limited portions of the production history were used (1 year, 2, 3, 4, 5, 7, 12, 15, 18, 20 years) to generate rate –time forecasts in which the hyperbolic model is switched to the exponential form at terminal decline rates of (0%, 2%, 3%, 5%, 7%, 10%, 12%).

Table 1: Properties of Base Case for Horizontal Well with Multiple Fractures

Reservoir Temperature	180	°F
Initial Reservoir Pressure	3500	Psia
Well Length	5000	ft
Fracture Half Length	200	ft
Fracture Spacing	400	Ft
Number of Fractures	13	
Formation Height	300	ft *
Reservoir Permeability	0.0001	md
Reservoir Porosity	0.03	
Fracture Conductivity	5	md-ft
Kv/Kh	0.1	

* The assumption is made that the fracture extends through the full thickness of the formation.

In fitting the rate- time production forecast, higher priority is given to matching the most recent data above the value of using all of the available production history. As such some matches use only one of two years immediately preceding the start of the forecast, while other matches honor the fully.

Figure 2- Figure 4 illustrates and summarize the analysis procedure. Figure 2 below shows the result of the base case evaluated with different minimum decline rates and the benefit of only 1 year of production history. The graph shows the simulated data in black and overlain on it is the production forecasts generated using the rate- time Arps equations. A minimum decline of 0% (Arps) is shown in the bronze color while increasing minimum decline rates shows faster declining production rates from 2% (green dashes) to 12% (purple). As indicated in the graph, the larger the decline rate the faster the production rate declines.

Included also is Figure 3 the rate-cumulative production forecasts for the same predictions. The graph represents the same Arps model parameters from the rate-time match applied in the rate – cumulative production equation.

As a complement, Figure 4 shows the evaluation at a single minimum decline rate (3%) for a set of selected times at which the forecasts are performed for the base case. Figure 4 shows year 1, 5, 10, 15 and 20 predictions but for each analysis years 1, 2, 3, 4, 5, 7, 10, 12, 15, 18, and 20 are used for forecasting

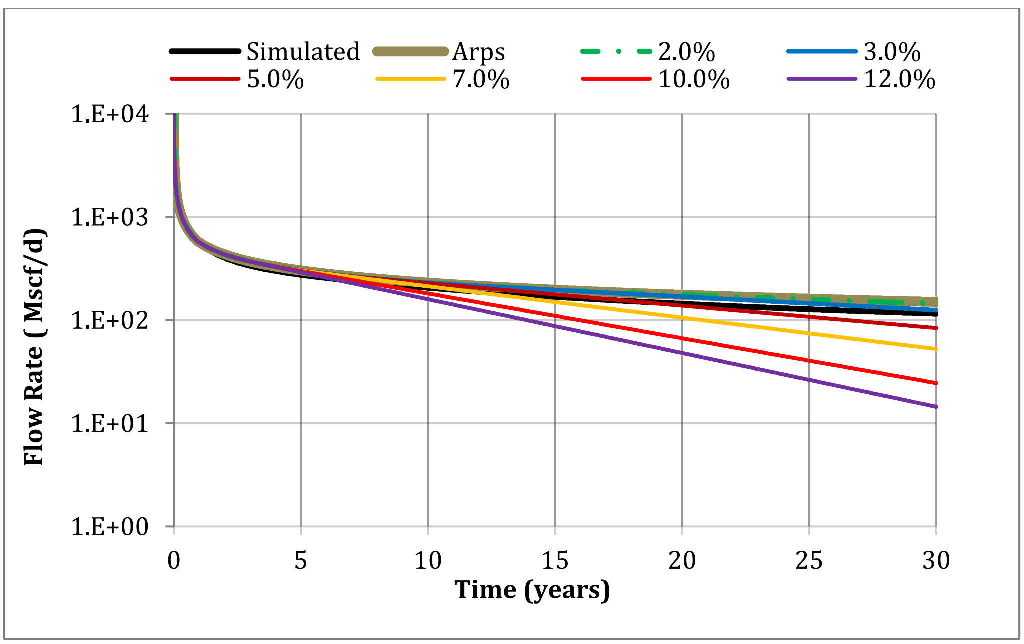

Figure 2: Comparison of simulated and projected rate – time profiles for different minimum terminal decline rates. Forecasts are made using one year of production history for the base case for MFHW.

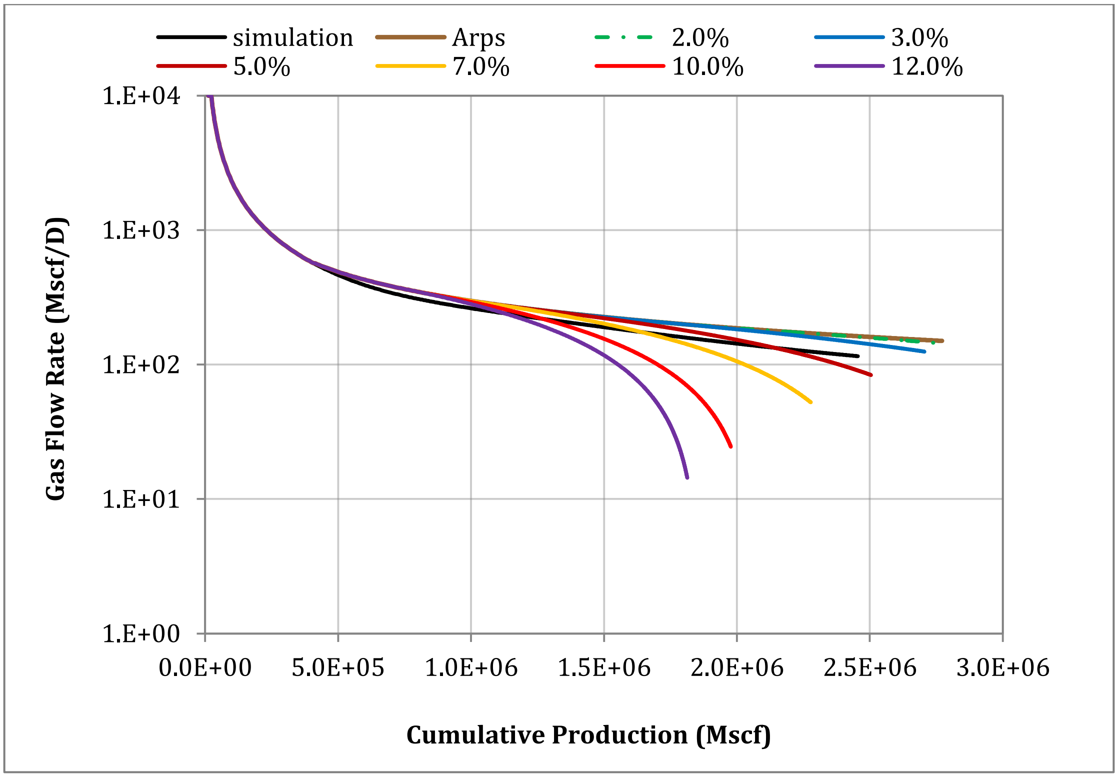

Figure 3: Comparison of simulated and projected rate- cumulative production profiles for different minimum terminal decline rates. Forecast is made using one year of production history for the base case for MFHW.

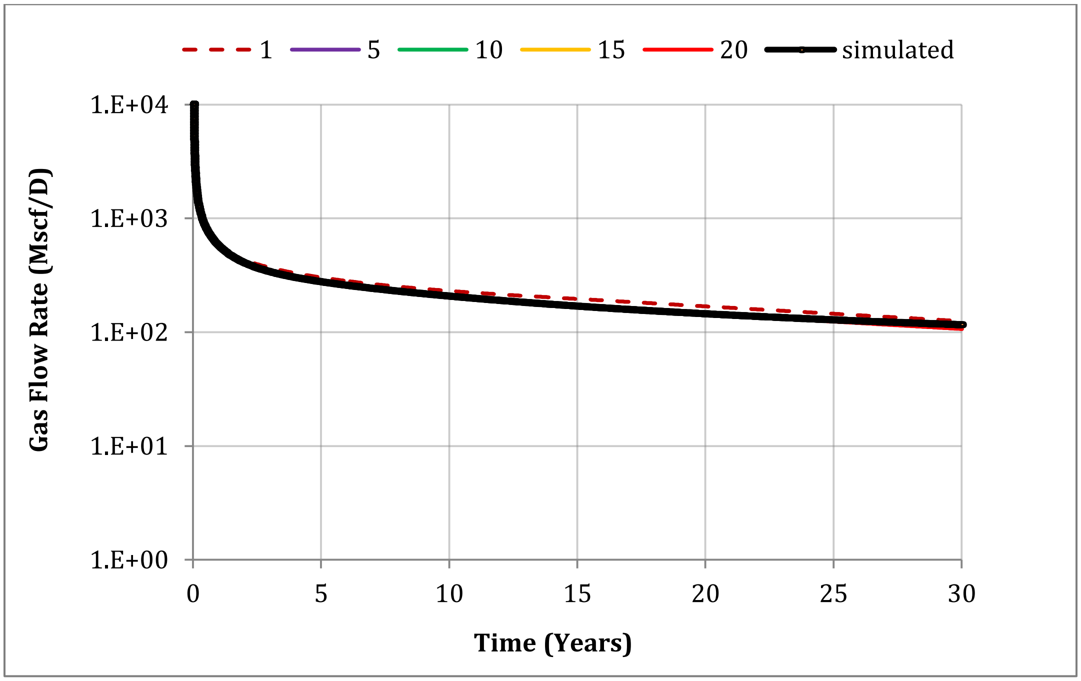

Figure 4: Forecast of rate-time production relationship for increasing quantities of production history for the MFHW base case and a minimum terminal decline rate of 3%.

The use of simulated data provides the additional advantage that the actual volume recovered is known. As mentioned above for this base case the EUR after 30 years is 2.544 BCF. For each analysis, the projected estimated ultimate recovery and remaining reserves are determined along with the associated relative percentage error in both values.

The outcome for any one well evaluated is a matrix of different predictions each related to a specific quantity of production data utilized and to a specific minimum terminal decline rate.

The appropriateness of the minimum decline rate method for forecasting production performance in horizontal wells with multiple fractures as well as the determination of the most appropriate minimum terminal decline rate is evaluated by the relative errors of the reserve predictions.

Figure 5 shows the relative error in the estimated ultimate recovery applied at selected time periods in the life of the well for the MFHW base case.

Several conclusions can be tentatively drawn from this lone figure. Firstly, the prediction of the estimated ultimate recovery improves when more production history is considered, having the worst prediction in year 1 and improving in each subsequent year. This imitates the various stages of the life of the well and confirms that what has been written by previous authors that more data results in better predictions. Larger minimum terminal decline rates result in smaller estimates of ultimate recovery and decline rates of 7%, 10% and 12% consistently, under-predict the EUR while applying the Arps hyperbolic equation (0%) often over-prediction of the reserves.

This result illustrates the effect of the compensating errors of the minimum terminal decline rate method. Imposing the exponential model at a specific predetermined minimum decline is intended to fix the typical over prediction of the Arps model. However if the switch to the exponential is made at too high a terminal decline rate the model will under-predict EUR.

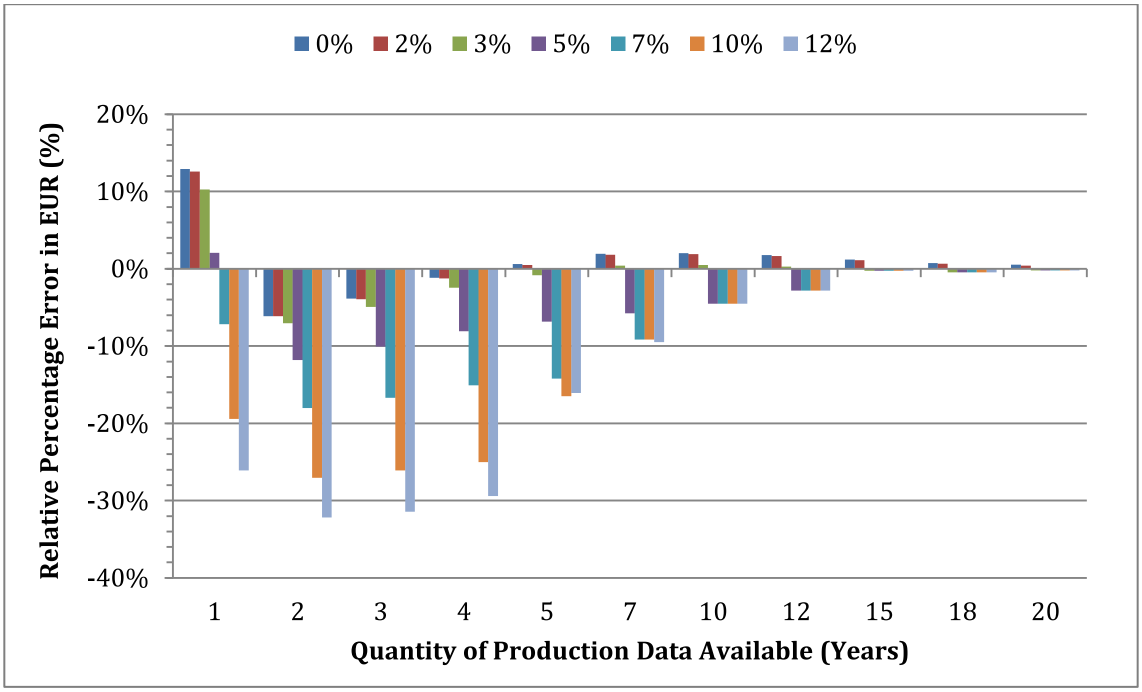

Figure 5: Variation in relative error in EUR for increasing quantities of production history and varying minimum terminal decline rates for the MFHW base case. The Arps projection is shown in blue bars and increasing minimum decline rates shown are 2% (marron), 3% (green), 5%(purple), 7%(bright blue), 10% (orange), and 12% (light blue). Decline rates of 7% and 12% are drastically under-predict reserves. Decline rates of 2-3% give fair approximation to the EUR at the end of 30 years.

Evaluation of the relative percentage error in remaining reserves, as mentioned previously, has given more weight than the error in EUR since it provides predictions of the future production and future income. Figure 6 shows the relative error in the remaining reserves and echoes the notion that decline rates of 7%, 10% and 12% are unsuitable for application to horizontal shale gas wells with multiple fractures since they consistently drastically under-predict remaining reserves and any financial calculations performed using these prediction would be extremely pessimistic.

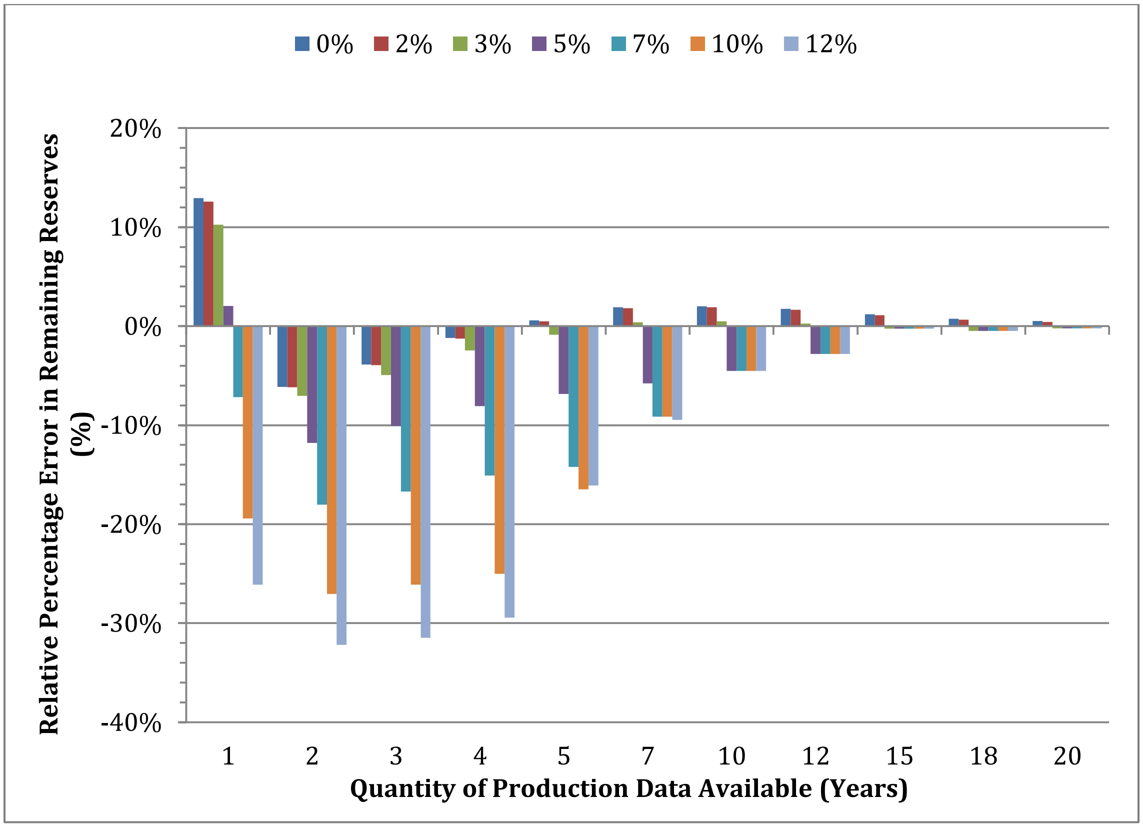

Figure 6: Variation in relative error in remaining reserves for increasing quantities of production data available and varying minimum terminal decline rates for the MFHW base case. The Arps projection is shown in blue bars and increasing minimum decline rates shown are 2% (marron), 3% (green), 5%(purple), 7% (bright blue), 10% (orange), and 12% (light blue). Decline rates of 7% and 12 % are drastically under-predict reserves. Decline rates of 2-3% give fair approximation to the remaining reserves at the end of 30 years.

As such the forecasts generated using this method can be subdivided based on the hyperbolic portion of the forecast compared to the exponential portion of the forecast. Further the remaining volumes predicted for the exponential portion of the forecast can also be compared to the simulated volumes produced subsequent to the models switch to exponential.

The comparison of the exponential portion of the forecast with the simulated quantity of reserves produced after the switch to exponential provides an indication of the fraction of the total error in the remaining reserves that can be attributed to the imposition of the exponential decline. Figure 7 shows the relative error and indicates that the smallest errors occur for the minimum terminal decline rate of 3%. A decline rate of 2 % tends to over-predict reserves while declines of 5-12% tend to under-predict reserves. The merging of the curves for longer periods of production history considered is caused by fact the decline at the start of the forecast had already falling beneath the predetermined decline rate for this particular well. In these cases the exponential forecast is continued at the current decline rate. The evidence presented in the three previous plots support the conclusion that an appropriate minimum decline rate for the simulated MFHW is 3%.

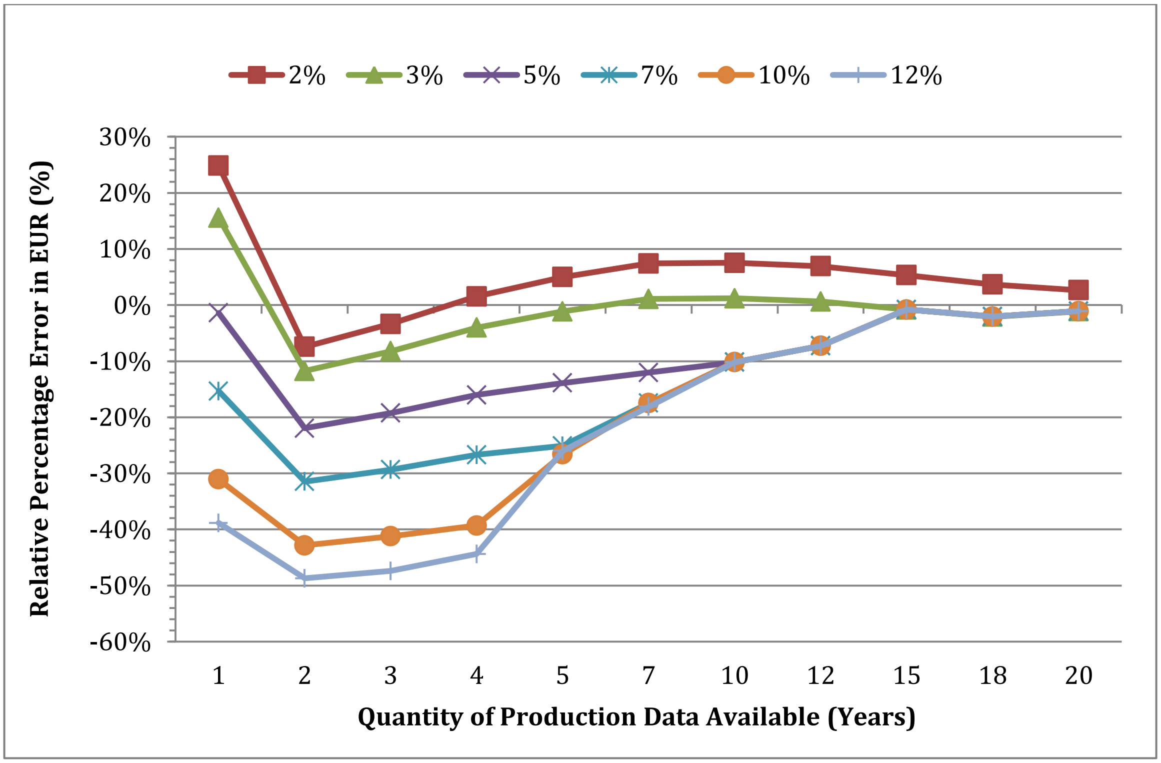

Figure 7: Variation in relative error in Remaining Reserves due to the imposition of exponential forecast for the MFHW base case evaluated using increasing quantities of production history and varying minimum terminal decline rates.

2.2 Systematic Study of Simulated Horizontal Wells with Multiple Fractures

The systematic study starts with the base case and variations are made by selecting a single well or reservoir property and varying that selected property within a range likely to be encountered in shale gas reservoirs. The results are sets consisting four (4) to six (6) simulations in which a single property is varied.

The work of several authors have shown that fracture complexity, formation permeability and the fracture conductivity have significant effects on the gas productivity and the ultimate volumes recovered- from a multi-fractured horizontal well. As such these are among the properties selected for variation.

Properties selected for variations in the unbounded horizontal well with multiple fractures are: dimensionless fracture conductivity, generated by altering the fracture conductivity, fracture half length, fracture spacing and fracture height. Selected reservoir properties have also been varied- formation height and reservoir permeability. Each simulation is evaluated in the same manner as the base case discussed above.

Table 2 below summarizes the full set of variations applied to horizontal wells with multiple fractures. For each forecast a minimum terminal decline rate of 3% has been applied since this was the decline rate that was most appropriate for evaluating the base case.

Table 2: Systematic Study of MFHW: Variations of Selected Properties

Selected Property	Base Case	Minimum	Maximum
Fracture Spacing (ft)	400	50	800
Fracture Half Length (ft)	200	50	750
Dimensionless fracture Conductivity	250	0.1	2500
Fracture Height(ft)	300	50	300
Reservoir Permeability (md)	0.0001	0.01	0.000001
Formation Height (ft)	300	50	600

2.2.1 Dimensionless Fracture Conductivity – F_{cD}

$$F_{cD} = \frac{k_f w}{x_f k_{res}} = \frac{F_c}{x_f k_{res}}$$

The dimensionless fracture conductivity is an essential parameter in designing any fracture treatment as it relates the ability of the fracture to transport fluid along the fractures and into the wellbore with the ability of the reservoir to supply this fluid. It is given by equation stated above and is the ratio of the fracture conductivity (fracture permeability and fracture width) divided by fracture half-length and the reservoir permeability.

The completion of a low permeability reservoir requires that sufficient fracture network connectivity and that the created fractures have and can maintain through the producing life sufficient fracture conductivity for economic production. The lower the reservoir permeability, the more critical these factors become. This is typically achieved by using large volumes of low viscosity fracture fluid and smaller proppant particles than can be transported deep into the fractures. The low density fluid create high fracture density geared at exploiting previously existing naturally occurring fractures while the further the proppant is transported into the fractures, the higher the fracture conductivity is likely to be.(Cipolla et al. 2009a, 2009b; Warpinski et al. 2009)

The base case for horizontal wells with multiple fractures had a fracture conductivity of 5md.ft which is equivalent to a dimensionless fracture conductivity of 250. Table 3 below shows the range of cases for dimensionless fracture conductivity which were generated and evaluated.

Figures 8 and 9 below summarizes the results of these evaluations when a minimum decline rate of 3% is applied to make rate – time predictions. Figure 8 shows the relative percentage error in EUR year 1 predictions range from -20% to +20 % but decline at year 20 to a smaller range of +/-2% at the 20th year, clearly showing that increasing production history results in a more accurate prediction. From Figure 9 it is evident that for these variations in dimensionless fracture conductivity, at least 20 years of production history are required if the estimates of the remaining reserves to be accurate to +/- 5% and more importantly predictions of remaining reserves using 2 years of production history are only +25% to -20% accurate.

Table 3: Variations of Dimensionless Fracture Conductivity F_{cD}

F_c, md-ft	k_f-md	width,in	X_f, ft	k_r, md	F_{cD}
0.002	0.096	0.25	200	0.0001	0.1
0.01	0.48	0.25	200	0.0001	0.5
0.05	2.4	0.25	200	0.0001	2.5
0.1	4.8	0.25	200	0.0001	5
5*	240	0.25	200	0.0001	250
50	2400	0.25	200	0.0001	2500

***Base Case**

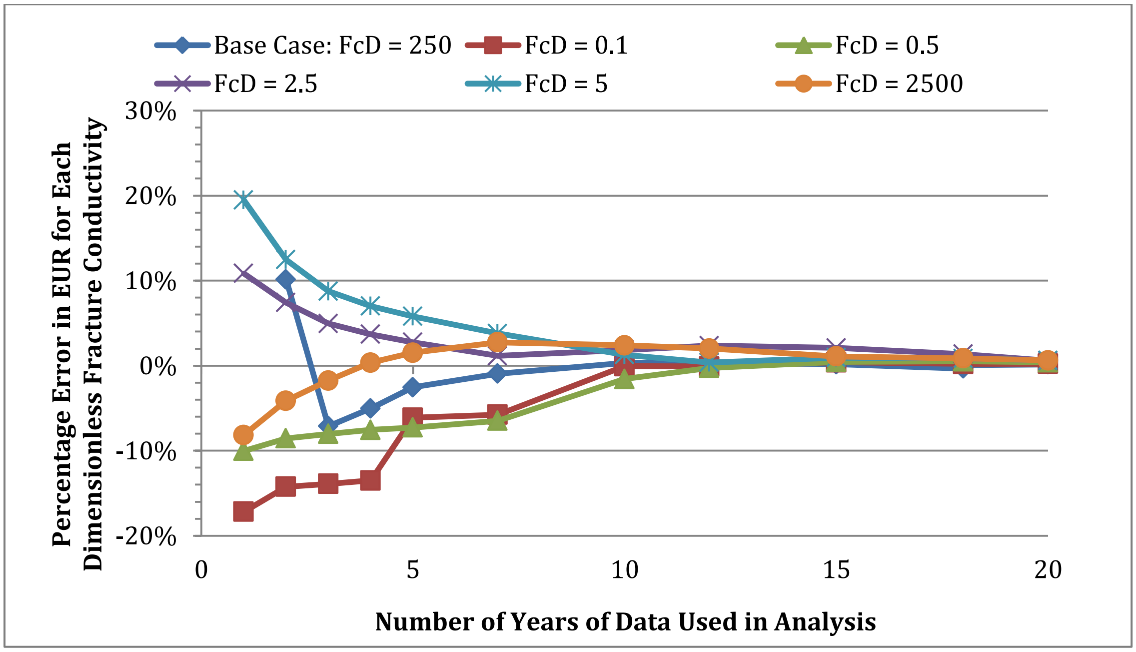

Figure 8: Variation of error in EUR evaluated for different dimensionless fracture conductivity and increasing production history. D_{min} = 3%.

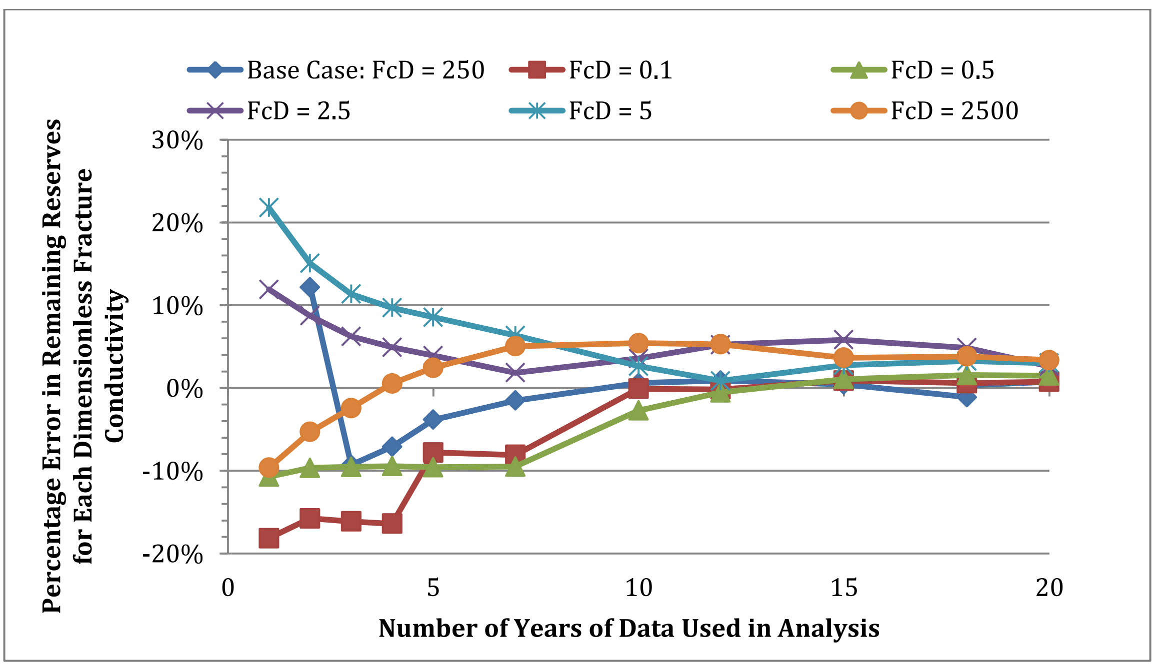

Figure 9: Variation in error in remaining reserves evaluated for different dimensionless fracture conductivity and increasing production history available. D_{min} = 3%.

2.2.2 Fracture Spacing

In this systematic study all of the horizontal wells have only primary fractures. There are no secondary fractures but the closer together the primary fractures are the more “complex” the network is. Increasing fracture complexity reduces the impact of the formation permeability (Cipolla et al. 2009b) an important factor when the formation permeability is on the order of 10^{-4}. The base case fracture spacing was 400 feet (13 fractures- 5000ft well length) and the variations in the fracture spacing range from as small as 200 ft (this is limited by Topaz because a maximum of 30 fractures is allowed in any one multi-fractured horizontal well) up a maximum of 800 ft. Table 4 below lists the simulations which were generated and evaluated.

Figures 10 and 11 below summarize the results. Generally the prediction improves with increasing data use and the best prediction is seen in the latest time evaluated- 20 years. More specifically, initial error in EUR ranges from -30 % to +90% but decreases to an almost uniform error of +/- 5% in the 20^{th} year. Additionally, Figure 11 confirms graphically that in order to achieve an accuracy of +/- 10% in remaining reserves, approximately 20 years of data is required. The accuracy of predictions made with the benefit of only one year of production history is between +120% to -40%.

Additionally, it can be observed from Figures 10 and 11 that for the smaller fracture spacing of 200 feet and 300 feet) the errors tend to be much higher than in the other plotted cases. This is attributed to the shape of the original rate- cumulative production- time curves. The initial production rates are extremely high as production is dominated by emptying the fractures but tapers during continued production. This results in a flatter curve and a longer transition period to what is assumed to be “fracture dominated flow- as opposed to formation dominated flow”. The increased error is attributed to the shape of the curves and these are some of the cases where partial production history was used to obtain the Arps model.

Table 4: Variations of Fracture Spacing

Well Length ft	Fracture Spacing ft	Number Fractures
5000	200	25
5000	300	17
5000	400	13
5000	480	11
5000	600	9
5000	800	7

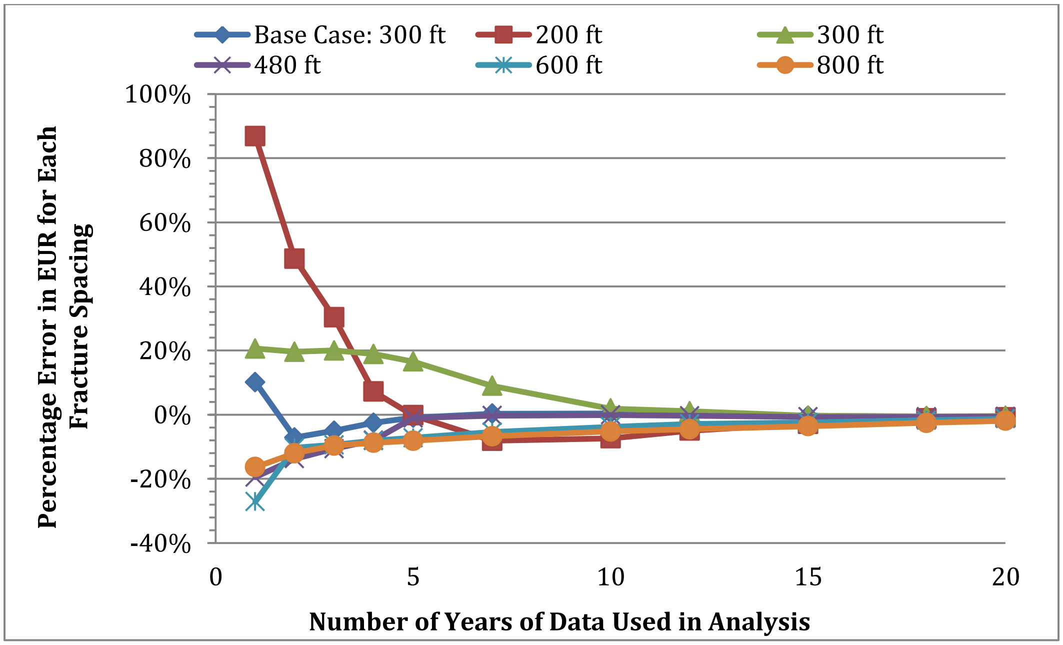

Figure 10: Variation in error in EUR for different fracture spacing and increasing production data available. D_{min} = 3%.

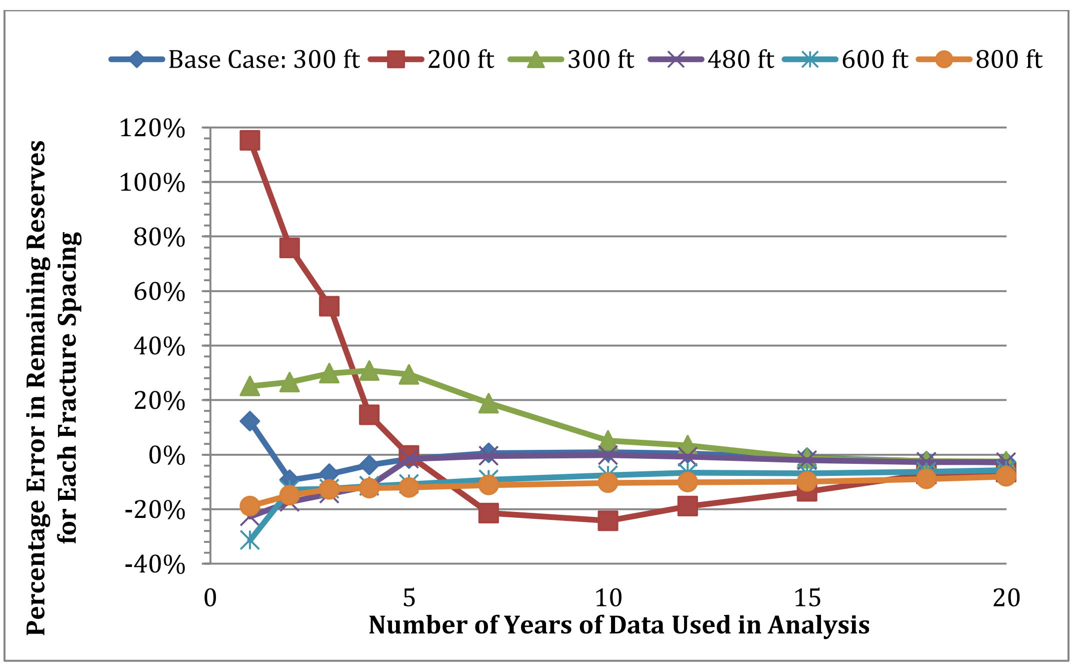

Figure 11: Variation in error in remaining reserves for different fracture spacing and increasing production data available. D_{min} = 3%.

2.2.3 Fracture Length

Fracture half-length describes how far from the main well bore the primary fractures extend. The fracture half-length in the base case is 200 feet and it is generally accepted that as the size of a complex fracture network increases so too does the production rates and recovery from the formation. As mentioned above, in this systematic study the horizontal wells have only primary fractures (no complex networks) and increasing the length of fractures increases the overall area in which the rock has been fractured- increased size of the network.

The fracture half-length has been varied from a minimum of 50 feet with the lowest cumulative production up to a maximum of 750 feet which has the maximum cumulative production. Prediction of EUR improves with increasing quantity of data considered and the relative error in EUR for the initial time period of 1 years ranges from -20% to +50%. Predictions of remaining reserves made with the benefit of one year of production history within -25% to +65 % accurate. This is illustrated in Figure 12 (error in EUR) and Figure 13 (error in remaining reserves).

In previous sets of selected cases (in this systematic study) it has been shown that 20 years of data are required to achieve and accuracy of +/- 10 % in remaining reserves. The same proves to be true for variations of fracture half length.

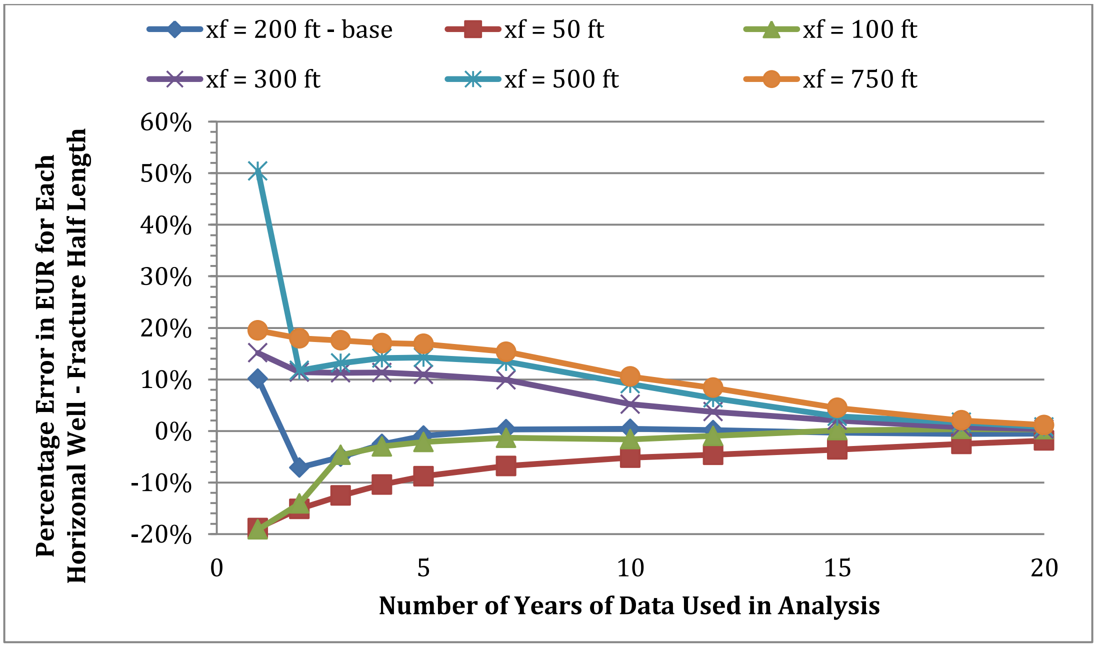

Figure 12: Variation in error in EUR for different fracture half-length and increasing production data available. D_{min} = 3%

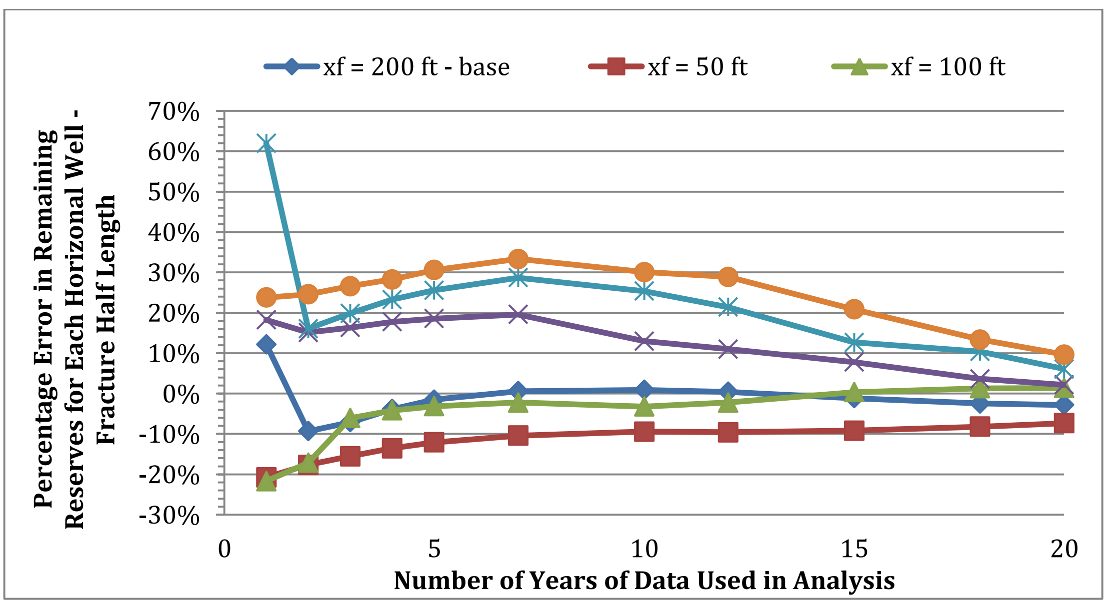

Figure 13: Variation in error in remaining reserves for different fracture half-lengths and increasing production data available. D_{min} = 3 %.

2.2.4 Fracture Height

The base case assumes that the fracture extends from to the top to bottom of the formation since it is the difference in the formation properties that causes the fracture to terminate. This subsection of the study assumes that the fracture may stop, probably due to internal variations in formation properties or alternatively due to poor fracture treatment design. Here the maximum fracture height is 300 feet as in the base case and decreases to a minimum of 50 feet.

As in the previously described cases, the best estimates of EUR and remaining reserves occur in the latest time – the maximum quantity of data evaluated is 20 years. The most inaccurate estimates occur in the shortest selected time (1 year): Error in EUR ranges from -30% to +10% while error in remaining reserves ranges from -35% to +15%. This is illustrated in Figure 14 which describes the error in EUR as well as Figure 15 which describes the error in remaining reserves for fracture height variations.

Predictions of EUR converge in the 20 year at almost -2 %. Accurately predicting the remaining reserves within +/- 3% requires a 20 years of data.

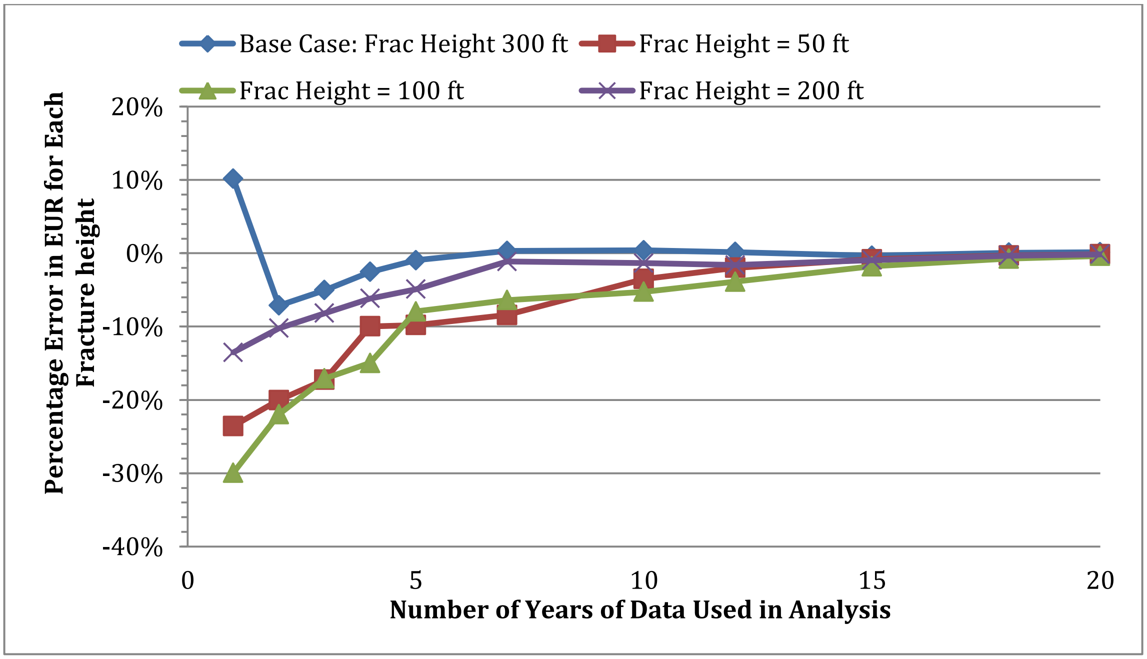

Figure 14: Variation in error in EUR for different fracture height and increasing production data available. D_{min} = 3%.

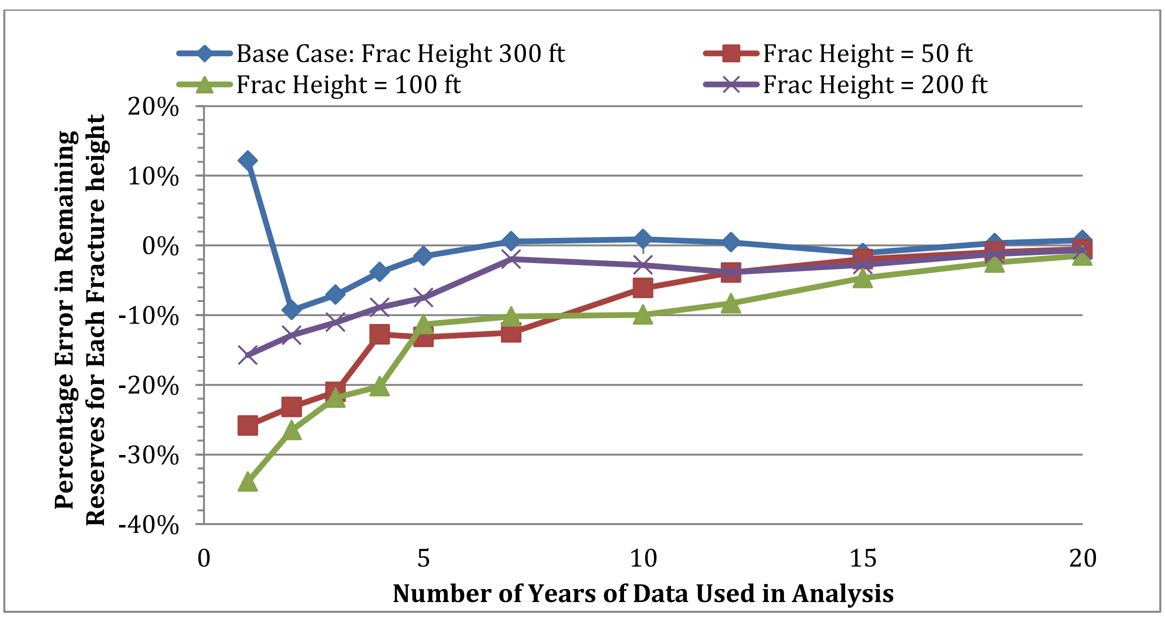

Figure 15: Variation in error in remaining reserves for different fracture height and increasing production history available. D_{min} = 3%.

2.2.5 Formation Permeability

The reservoir permeability of the base case is $1e^{-4}$ md in line with the stated average reservoir permeability of the Barnett Shale. The permeability has been varied by multiples of 10, with a maximum of $1e^{-2}$ md, which is an order of magnitude smaller than the upper permeability limit for tight gas formations as defined by the US government to a minimum of $1e^{-6}$ md. Naturally, reservoir permeability plays an important function in defining the deliverability of any formation and the higher the absolute permeability, the higher the deliverability can be expected to be. Figures 16 and 17 show similar trends to the previously discussed variations in the systematic study. Figure 16 confirms that more production history available results in more accurate predictions of EUR. The predictions in EUR at the 10th year are within +/- 5% and a similar error is seen in the 20th year.

Trends in the relative error in remaining reserves give better results than the other variations in that although the initial errors are quite high -30% to +40%, only 10 years of production history is required to get an accuracy of +/- 10 %.

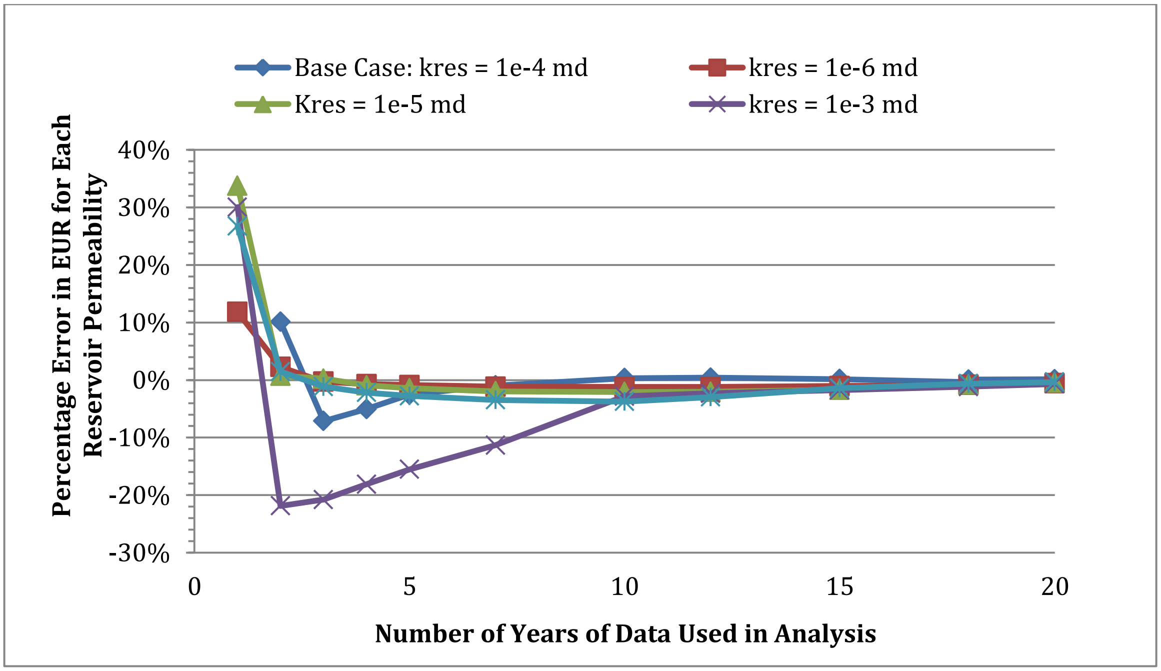

Figure 16: Variation in error in EUR for different reservoir permeability and increasing production data available. D_{min} = 3%.

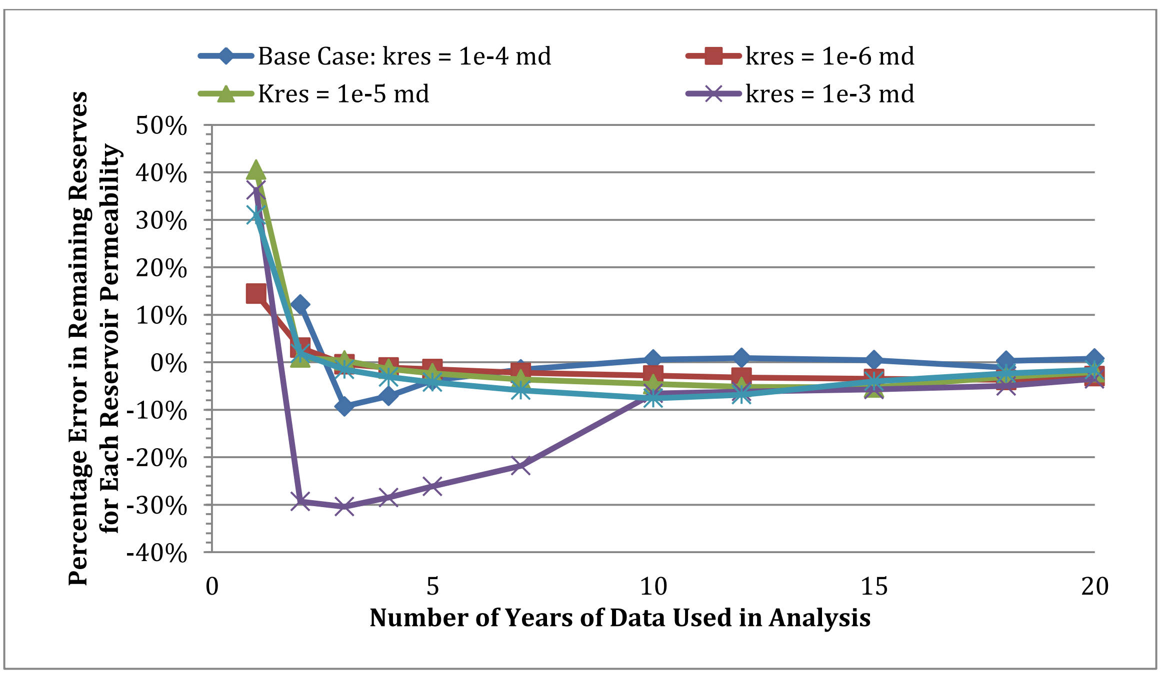

Figure 17: Variation in error in remaining reserves for different reservoir permeability and increasing production data available. D_{min} = 3%.

2.2.6 Formation Thickness

The formation height for the base case is 300 feet. Cipolla has provided ranges for typical formation ranges for the Barnett shale formation. That range is between 50 feet to 600 feet and a similar range has been investigated in this systematic study. Figure 18 shows that for the formation height cases, the errors in EUR converge and become almost uniform after the 15 years, confirming that having the benefit of additional production history, increases the accuracy of the prediction. Figure 19 shows a similar trend for the evaluation of errors in remaining reserves. The initial error ranges -25% to +20% with one year of production history but these errors are reduced to +/- 5% in the 20th year.

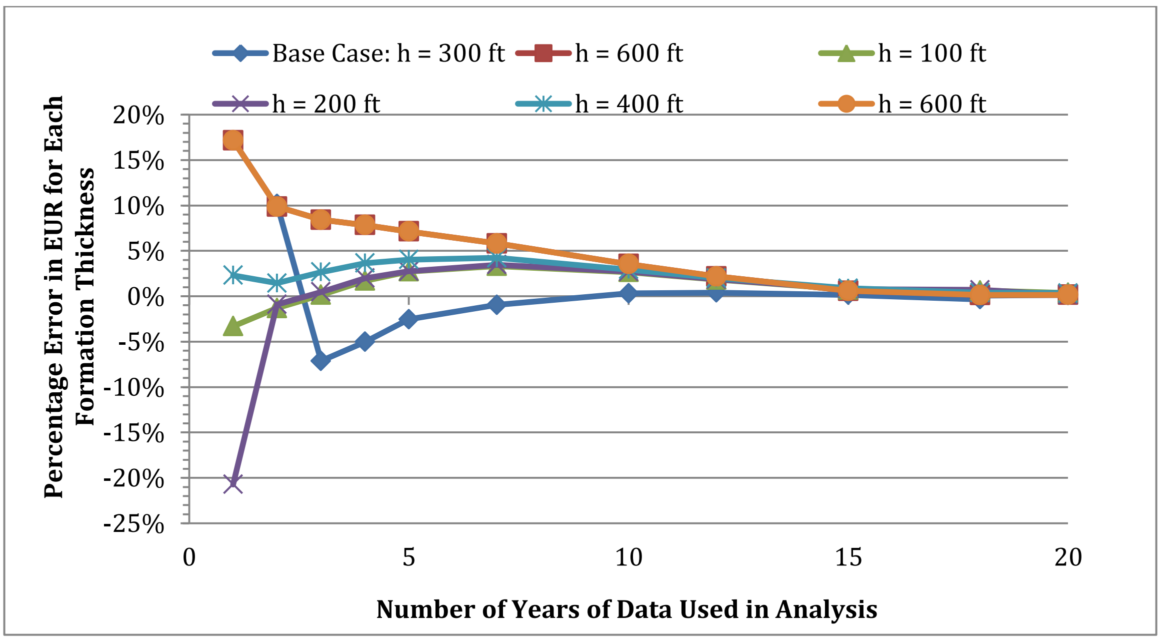

Figure 18: Variation in error in EUR for different formation thickness and increasing production data available. D_{min} = 3%.

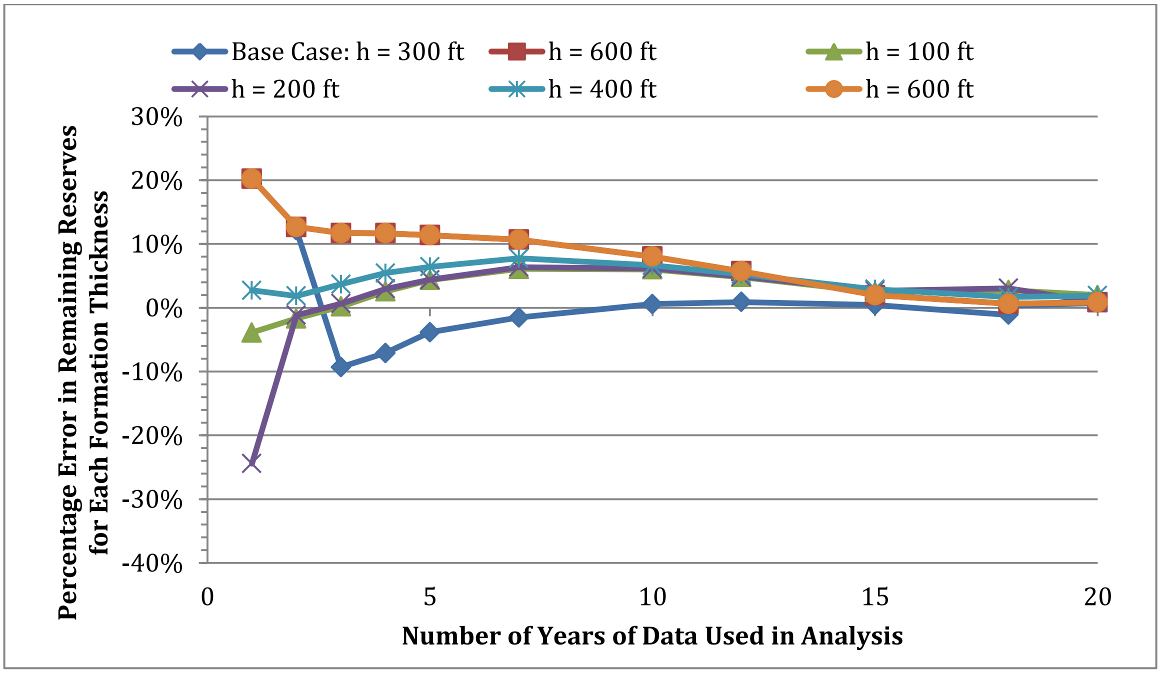

Figure 19: Variation in error in remaining reserves for different formation thickness and increasing production data available. D_{min} = 3%.

These errors ranges are set to encompass all of the simulated results, though it noted that the evaluation of some simulations provide significantly better results. Evaluation of the systematic study, using the terminal decline rate of 3% reveal that for variations of dimensionless fracture conductivity, fracture half length, fracture spacing, fracture height, reservoir permeability and formation thickness, the errors in EUR and Remaining reserves at the 30th year are

- Estimated Ultimate Recovery:
  - 2 years +/- 50%
  - 10 years +/- 12%.
  - 20 years +/- 3 %

- Remaining Reserves:
    - 2 years +/- 80%
    - 10 years +/- 20
    - 20 years +/- 7%

This outcome suggests that the application of the minimum terminal decline rate method at early times may be more highly regarded than deserved. It illustrates that significant quantities of production history are required to predict remaining reserves to within +/- 7 %. In an environment where engineers are often required to predict performance with as little as 6 months of production history, the stated errors ranges provide note of caution if using small quantities of production history.

2.3 Real Barnett Shale Well Data: Horizontal Well with Multiple Fractures

The previously presented simulation data is based on the published work by Cipolla (Cipolla 2009). In accompaniment to these simulations, real well data from Barnett shale sourced through the drilling info website has been evaluated.

The Barnett shale formation is located in north central Texas Forth Worth basin and was first discovered in 1981 but economic production from the field started in the late 1990’s. Throughout the fields life, the applied completion technology has changed from vertical wells with simple fractures, to horizontal wells with multiple fractures and at present the most widely utilized completion strategy is horizontal well multiple fractures completed using several fracture stages (Fisher et al. 2004).

Several wells with real data have been analyzed, some have been completed prior to the latest change in completion practices in 2004 and but the majority analyzed have had the newest completion strategy- since this is what had been simulated and is therefore appropriate for comparison. The use of this data reflects the most recent change in completion strategy but limits the production data that could be analyzed to just greater than six (6) years.

These evaluations also shed light on the difficulties of forecasting production rates and EUR with limited well life, low data frequency, poor data quality and sometimes frequent well interventions that alter well performance.

Limited well life: Often engineers are asked to predict performance with as little as 6 months of production history. This is entirely possible if the data conforms to a clear pattern but can be quite difficult if it does not. The example of Devon operated well with API: 42-497-35635 is an example of a well with a clear and consistent production profile that has been forecasted to cumulative production at the sixth year with accuracy between 1.5% and 7%. Unfortunately, six years of life represents the complete production history for this well. Although encouraging this is insufficient data to determine an appropriate minimum terminal decline rate or predict long term accuracy of the method in this completion type in the Barnett Shale.

Low data frequency: The data used in these evaluations are the publicly available production histories with one production value per month. If for any one or two days for the month the well is shut-in, this can have a significant impact on the recorded data affecting the production profile and the ability to make predictions. In these evaluations data points judged to be errant have been eliminated from consideration but the decision to edit out any data points that do not fit the trend is always a controversial one.

Finally frequent well work-overs or re-stimulations warrant that the evaluation restarts after these well interventions and limits the length of time over which the evaluations can be valid.

Nonetheless several real Barnett shale wells have been evaluated. These are tabulated in Appendix A and the evaluation of real Devon operated well with API 42-497-35635 is presented followed by EnCana operated well with API 42-121-32244.

2.3.1 Devon Operated Wise County Well. API: 42-497-35635

This well was completed and started producing in December 2004. The partial month of production as well as three months of erratic data have been eliminated from the evaluation. Production data is available up to December 2010 and a plot of the full production history for monthly recorded production volumes as well as the cumulative production is shown in Figure 20.

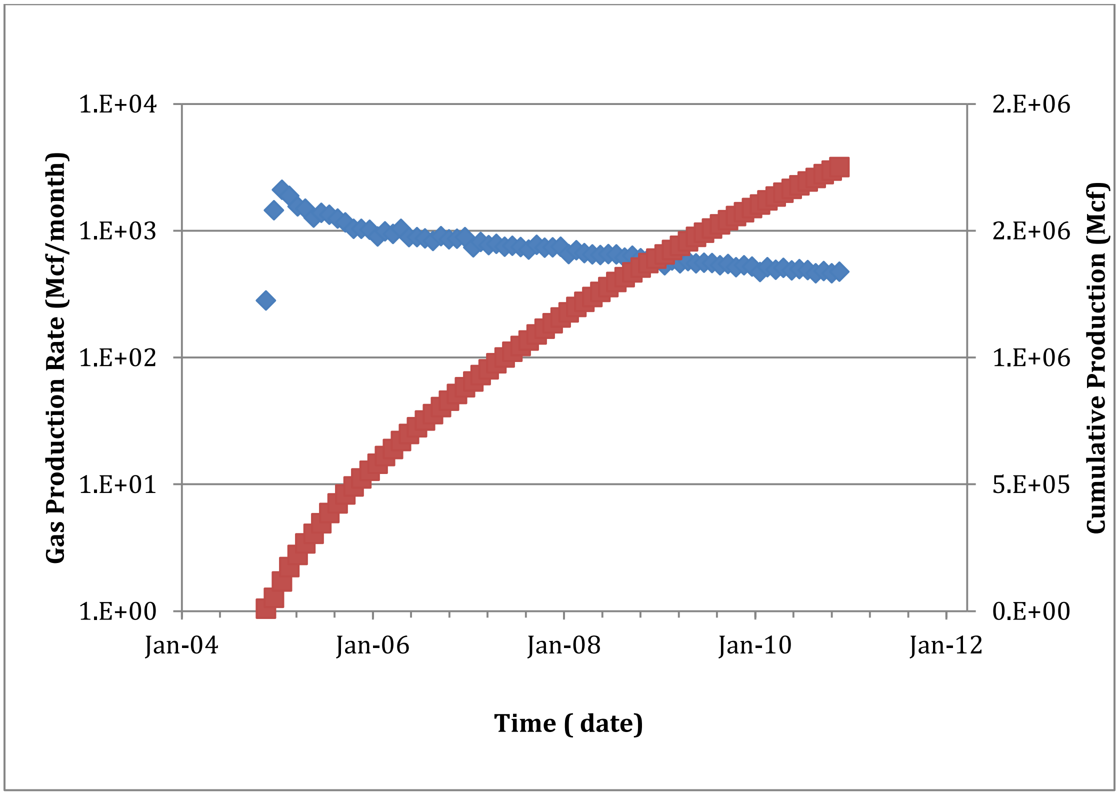

Figure 20: Production history for real Devon operated well API: 42-497-35635.

The cumulative production which occurred prior to the application of the Arps parameter fits is added back at the end of the analysis to maintain consistency. The edited data set is then evaluated using the same methodology applied to simulated data except that cumulative production at the end of the known well life is used as a "EUR" to that point in the well life. Devon operated well 42-497-35635 produced a volume of 1.75 BCF in 6.08 years. In addition to this analysis, a forecast of the well performance to the end of the 30th year using all of the available data is conducted. The results regarding the ability to fit this data set and predict the cumulative production at the 6th

year are quite encouraging but there insufficient data from which to determine the minimum terminal decline rate.

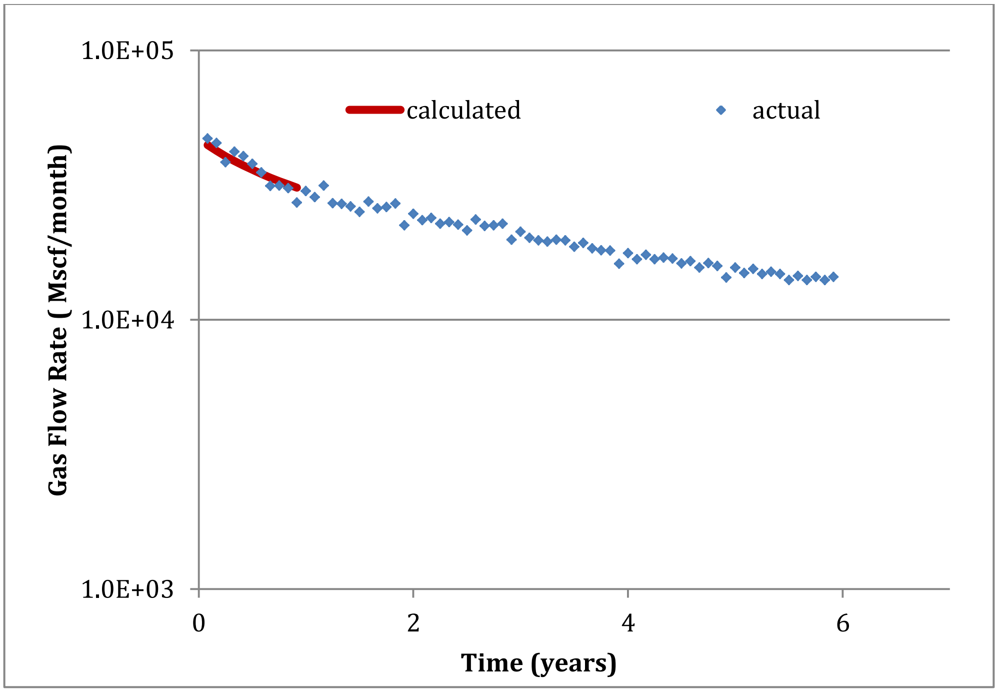

Figure 21: Arps hyperbolic rate time match to one year of production history for Devon operated Wise county well with API 42-497-35635. Matched parameter are q_i = 47071 mcf/month, b = 1.86, D_i = 0.69 yr^{-1}.

Figure 21 above shows the match using one year of production history. This match provided good predictions over the short time horizon of 6.08 years. Predictions for this time period indicate that the wells' decline rate is still greater than 7% resulting in identical prediction for decline rates of 0% to 7%. From the evaluation of simulated Barnett shale data it was determined that an appropriate minimum terminal decline rates is 3%. Applying a 3% decline rate, the predictions of the relative error in cumulative production was 1.56% and the approximation of the remaining reserves to be produced up to the 6.08 years was predicted with an accuracy of 2.40%.

A look at the results obtained from predictions made using different minimum terminal decline rates with increasing quantities of data to forecast production at the 6th year is presented in the Figure 22. All of the errors, for the entire decline rates applied are less than 7%.

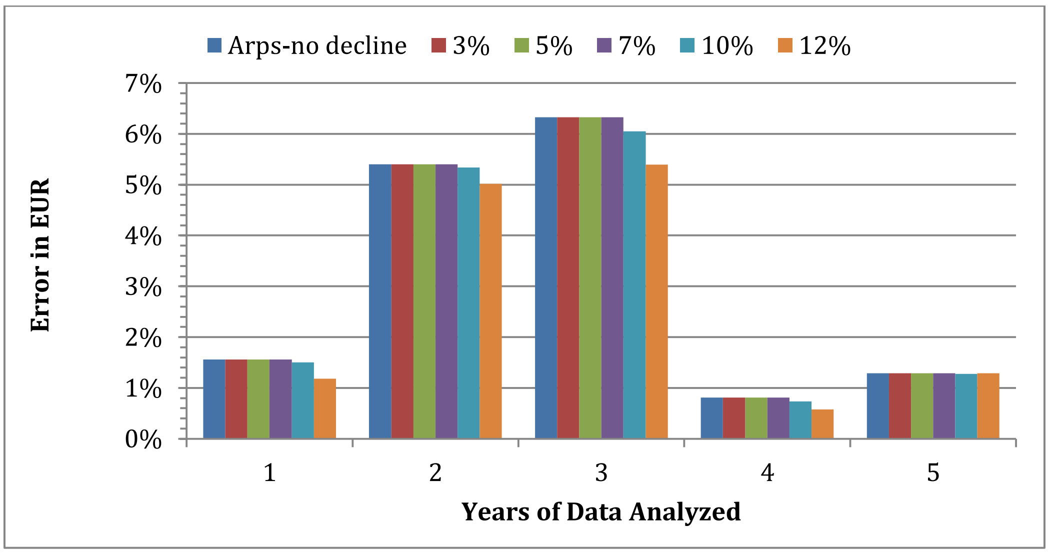

Figure 22: Error in cumulative production to the end of 6.08 years for Devon operated Wise county well (API: 42-497-35635). This is evaluated using different minimum terminal decline rates and increasing quantities of production history. Actual cumulative production at the 6.08 year of 1.75 BCF.

These are extremely good predictions over the short time horizon and the ability to fit this data so well provides hope that if the well life were longer, it would be possible to determine the minimum terminal decline rate, correctly apply the minimum terminal decline rate method and possibly get good predictions of EUR and Remaining Reserves.

The forecast to the end of the 30th year using all of the minimum terminal declines rates 0% Arps to 12% shows a particularly wide range of possible outcomes. These predictions use the full 6.08 years of available production history. The Arps hyperbolic model (0%) projects a volume of 4.13 BCF compared to 3.12 BCF decline rate of 12%. It is imperative that an appropriate minimum decline rates is applied to this evaluation in the long term and it underscores possible errors if this values is not known. Figure 23 below shows the wide range of possible outcomes for the varying minimum decline rates applied.

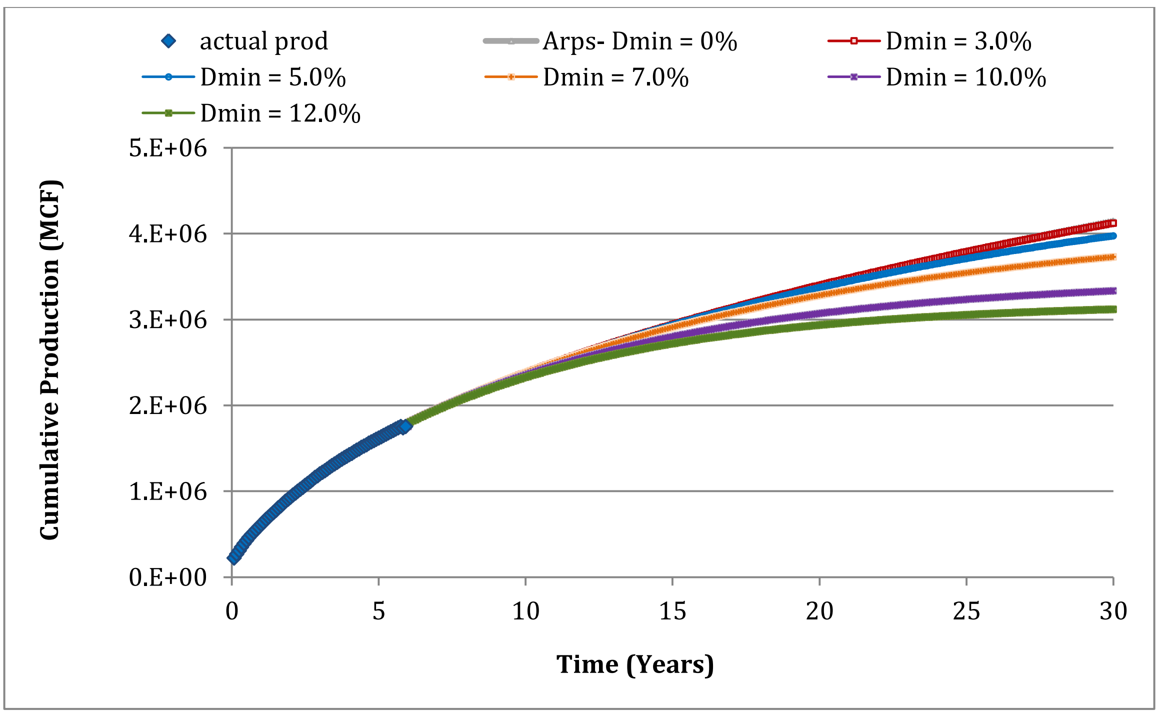

Figure 23: Cumulative production-time forecast for Devon operated Wise county well with API: 42-497-35635. Shows the range of predicted EUR at the end of 30 years different decline rates.

2.3.2 EnCana Operated Denton County Well. API: 42-121-32244

EnCana operated well with API 42-121-32244 drilled on the Range lease in the Newark East Field in Denton County and completed in June of 2004 is presented below. API 42-121-32244 produced 1.038 BCF from the date of completion to the last available production point (December 2010). This volume is the “EUR” to which the predictions are compared.

Figure 24 shows a plot of the real production profile for API: 42-121-32244 compared to the simulated fracture spacing variation of the MFHW base case. This is highlighted because of the one of the major changes is the decrease in primary fracture spacing and the use of multiple fracture stages.

Once the real data has been edited the rate-time Arps hyperbolic model is generated at the end of six months and year ends 1, 2, 3, 4, 5 and the end of the well life at 6.58 years. For each fit only the data that occurred prior to the match point is considered. The rate –time match at the end of 6 months shown in Figure 25, indicates a good match of real and calculated data. All of real data lies in close proximity to the red line which represents the Arps hyperbolic rate-time match. The complete production history for the well is utilized and there is no ambiguity about any of the recorded data points during the first 6 months. On the contrary, the Arps rate – time fit for 5 years of data provides a different picture.

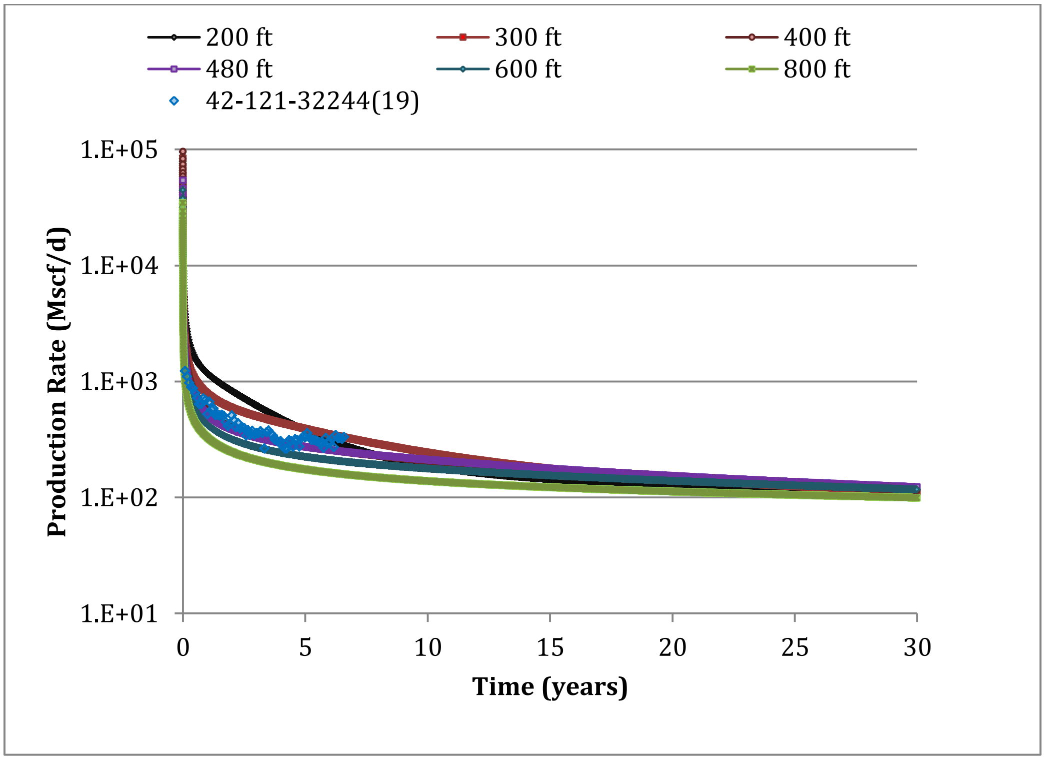

Figure 24: Real data for EnCana operated 42-121-32244(19) compared to the production profile for different fracture spacing cases for horizontal well with multiple fractures. The plot shows that the fracture spacing of 480 approximates the performance of the real well data.

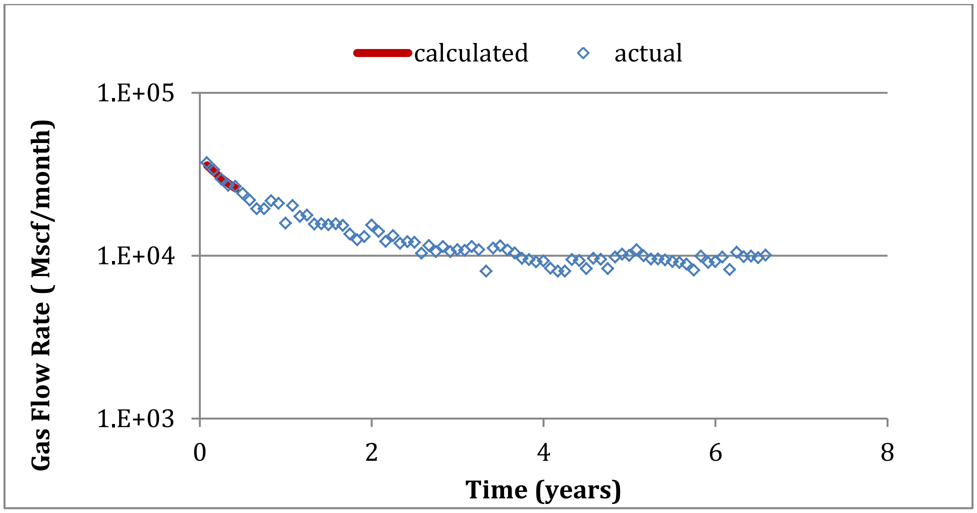

Figure 25: Match of calculated to actual rate-time profiles for EnCana operated API: 42-121-32244(19), using 6 months of production history. Arps hyperbolic fit parameters are q_i = 40 mmcf/d, b = 1.311, D_i= 1.405 yr^{-1}.

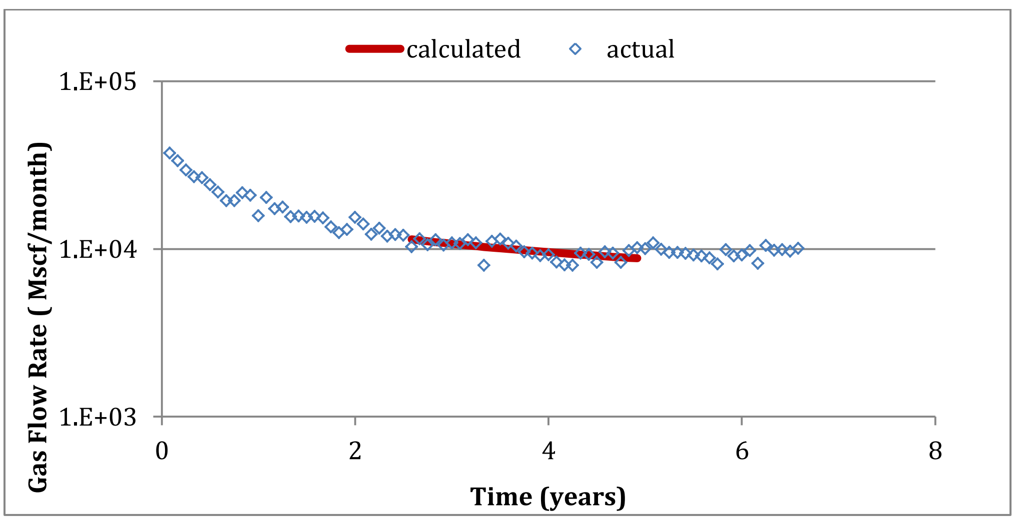

Figure 26: Match of calculated to actual rate-time profiles for EnCana operated API: 42-2-121-32244(19), using 5 years of production history. Arps hyperbolic fit parameters are q_i = 40 mmcf/month, b = 2.398, D_i = 3.12 yr^{-1}.

Figure 26 above illustrates the rate-time match at the end of 5 years of production history. Due to the almost undulating pattern of the data and the higher priority given to matching the most recent production, only the last half of the production data up to the end of the 5 years is considered. The match is adjudged to be the best fit but is not necessarily a good fit. The red line marks the projections of the Arps hyperbolic rate – time fit and the blue data points which represent the real data are scattered around in an S shaped pattern. It simply is not possible to use the Arps hyperbolic rate-time forecast in this situation and get a good fit.

Once the rate –time Arps hyperbolic fit is achieved, the minimum terminal decline rate is then applied using decline rates of 0% (Arps), 3%, 5%, 7%, 10% and 12%. Graphs showing the error in the EUR and a comparison of real and calculated volumes of remaining reserves are shown in Figures 27 and 28 respectively.

Figure 27 reflects the good fit of the first 6 months of real well data. The error in the EUR is approximately -12%. This is a fairly good match especially considering the undulating nature of the future production.

The evaluation of simulated data showed a clear trend of improving predictions for increasing quantities of production data analyzed. However this EnCana operated well API 42-121-32244 does not show this trend. The error in "EUR" for the 5th year is +13%. This is because it is simply not possible to perfectly match undulating data.

One possible means to reduce the scatter is by either eliminating or reducing the weight of some data points but there is no indication of which data points are more valid than others. Ignoring one data point means that an entire 30.4 days of production history is simply not considered and this can potentially be a significant portion of a short well life. This makes it difficult to forecast confidently.

Another alternative is to use production history with higher data frequency at least weekly but preferably daily. This higher data frequency would provide not only more data points but also allow for more liberal editing of the data- Unfortunately this is often not available publicly.

In addition to higher data frequency, firsthand knowledge of well activities would provide a distinct advantage. For wells with low monthly production, if one knows that the well had been shut in for a few days, then this knowledge would provide a means to make adjustments to the inputted data.

The outcomes for projecting EUR to the thirtieth years using 0.6 years and 5 years for this well are quite different. If it is assumed that an appropriate minimum terminal decline rate is 3% is applicable the predictions from 0.5 years is 1.78 BCF compared to 2.42 BCF a significant difference of 0.64 BCF.

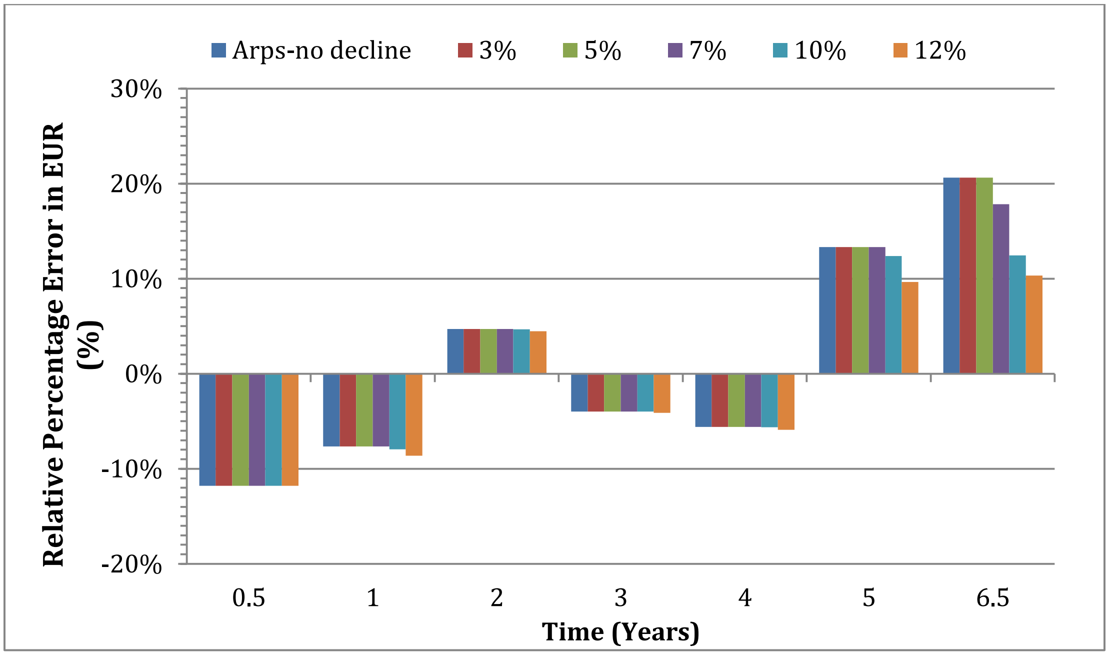

Figure 27: Relative error in "EUR" (cumulative production to 6.83 years) for EnCana operated Newark East Barnett Shale Well. API: 42-121-32244.

Figure 28 below compares those volumes of the predicted and actual remaining reserves for each evaluation and the message is similar that what has been already been stated. Further, Figure 28 shows that for predictions of remaining volumes, values are all either under-predicting or over-predicting and that there is little difference in the predictions for different minimum terminal decline rates. In particular, after 6 months all of the predictions for different minimum terminal decline rates are identical because the wells' decline rate is still above 12%. Similarly the decline rate at the last evaluated point is above 5%. The imperfect predictions for this well are not due to the choice of a minimum terminal decline rate but rather due to the inability to match the data accurately and the imperfect Arps hyperbolic b value that results.

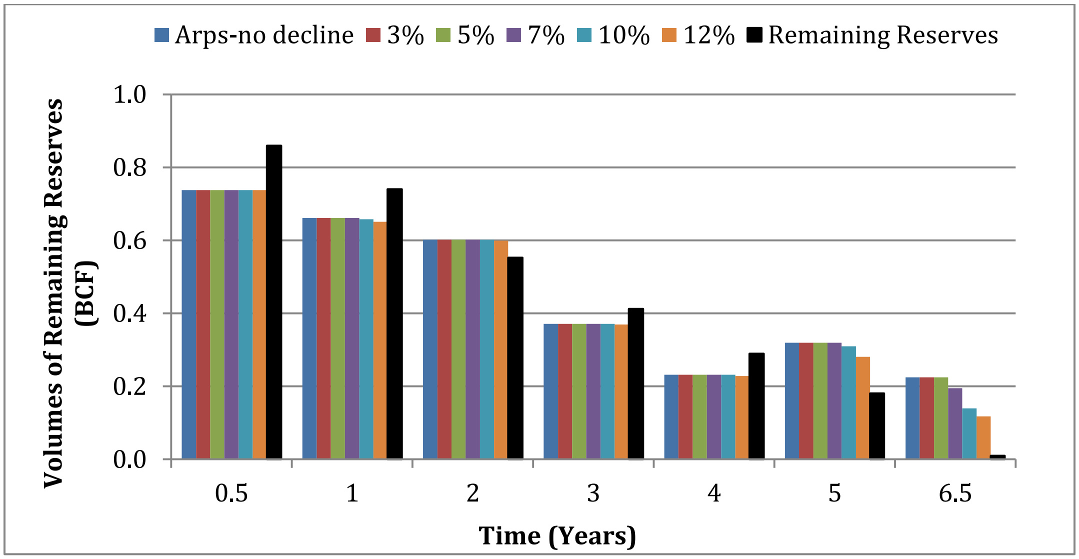

Figure 28: EnCana operated Newark East Barnett Shale Well. API: 42-121-32244- Comparison of calculated and actual remaining volumes to be produced by 6.83 years.

The results of applying the minimum terminal decline rate method to real well MFHW data from the Barnett Shale, with the new completion type is mixed one. If the evaluated well provides a clear and consistent production trend, a good fit of the Arps hyperbolic model is possible. In some cases for short time horizons it is possible to predict with good accuracy what the cumulative production at the current end of the well life is. In other circumstance, even the ability to make an Arps Hyperbolic match are greatly impeded by the scatter of the data. Unfortunately, in all cases there is insufficient production history to determine an appropriate minimum terminal decline rate.

III. VERTICAL LAYERED WELLS WITH FRACTURES

3.1 Base Case for Vertical Fractured Layered Wells

The same approach the evaluating the MFHW in shale gas formations applied in the previous chapter is also utilized for Vertical Fractured Well in Layered Formations. Essentially, the defining and analysis of a base case is followed by conducting a systematic study by varying key fracture and reservoir properties are and finally evaluating real well data.

The real well data for the Vertical Fractured Layered completion type comes from the Carthage Cotton Valley Field. The Cotton Valley field is located in North Lousianna and East Texas and has been has economic gas production since 1971 (Lyons and Asseff 1982). This field was originally drilled on a 640 acres well spacing but infill drilling has reduced the well spacing to 320 acres in the early 1980's and eventually to current well spacing of 160 acres. A review of the published literature revealed the work of that Meehan and Pennington (Meehan and Pennington 1982) who matched the numerical simulations to real field data for two Carthage Cotton valley wells in order to estimate well and reservoir properties.

This provided the start point for the base case of the Vertical Fractured Layered wells but the well and reservoir properties were modified to give a good agreement the publicly available real production history for this field. Several of the wells drilled in the 1980's gave similar production profiles. One of these wells against which the production profile was matched is the Conoco operated, Panola County well with API: 42-365-

31921. The well has been produced to abandonment and gives an indication of the production performance of a Cotton Valley well. By using this well we are not insinuating that it is typical of all Carthage Cotton Valley well performance from that era but we do feel that represents a particular type of well. A plot of the settled base case along with production data from API: 42-365-31921 is presented below.

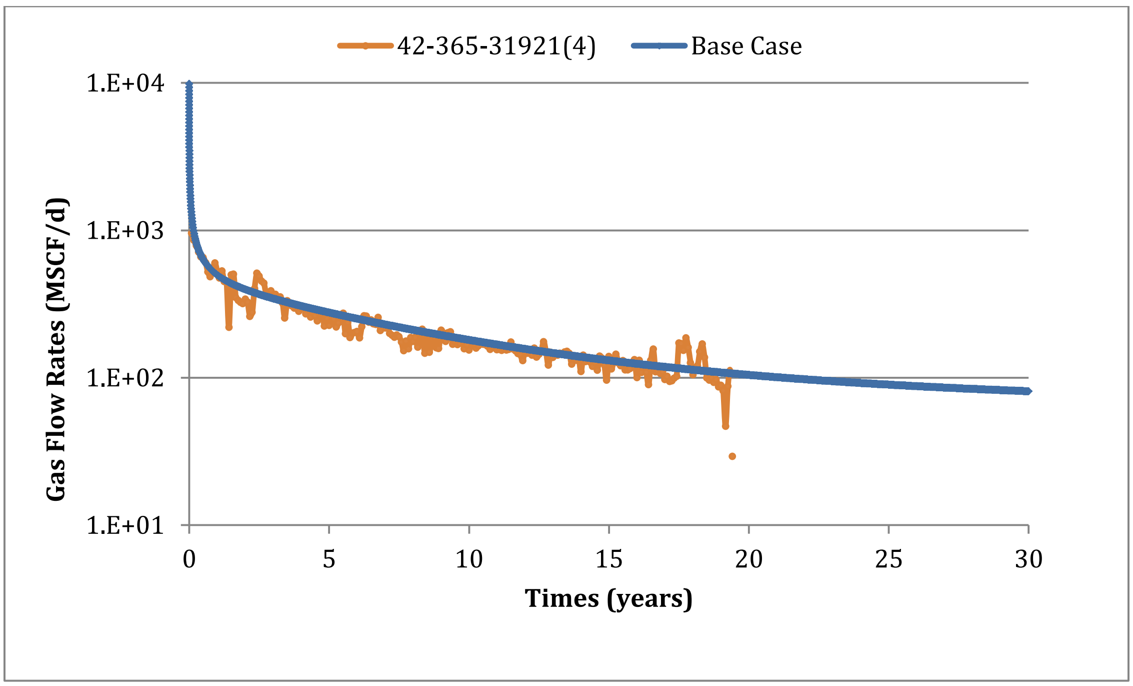

Figure 29: Match of settled base case for vertical fractured layered well with production profiles for Conoco operated Panola county well API: 42-365-31921.

The settled base case is a well centrally located in a square reservoir with no-flow boundaries and well spacing 320 acres. The reservoir is separated into three distinct homogenous layers. Properties of these layers are listed in Table 5 below. Although the final result of reservoir properties may not closely resemble the original sources, the layering pattern in the simulated well follows that which is typically observed in tight layered gas reservoirs- that the majority of the producible reserves (highest permeability) are located in the thinnest layer while the thickest layer has the lowest permeability (Lee and Hopkins 1994)

Table 5: Properties of Base Case for Vertical Layered Fractured Wells

Property	Layer 1	Layer 2	Layer 3
Well spacing (acres)	320	320	320
Thickness (ft)	30	60	12
Horizontal Permeability (md)	0.0035	0.0012	0.042
Porosity (fraction)	0.05	0.03	0.065
FcD- Dimensionless Fracture Cond	300	300	300
Fracture Conductivity (Fc)	735	252	8820
Fracture Half Length (ft)	700	700	700
Skin	0	0	0
North-Boundary	No Flow	No Flow	No Flow
South-Boundary	No Flow	No Flow	No Flow
East-Boundary	No Flow	No Flow	No Flow
West-Boundary	No Flow	No Flow	No Flow

The synthetic data for the base case, evaluated to the end of the 30 years gives an Estimated Ultimate Recovery of 2.03 BCF and the decline rate at the end of simulated life is 1.74%. The analysis procedure is identical to that applied for the previous completion type- horizontal wells with multiple completions. Accordingly plots showing the production profiles generated for the use of different minimum terminal decline rates applied using 1 year of production history is shown in Figure 30. A companion plot is shown in Figure 31 which illustrates the application of a terminal decline rate of 7% for increasing quantities of data production history.

Finally Figures 32, 33, 34 show the relative errors in EUR, the relative error in remaining reserves and the relative error in remaining reserves caused by the imposition of the exponential model and evaluated with the benefit of 1, 2, 3, 4, 5, 7, 10, 12, 15, 18, 20 years and for the minimum terminal decline rates of 0%, 2%, 3%, 5%, 7%, 10% and 12%.

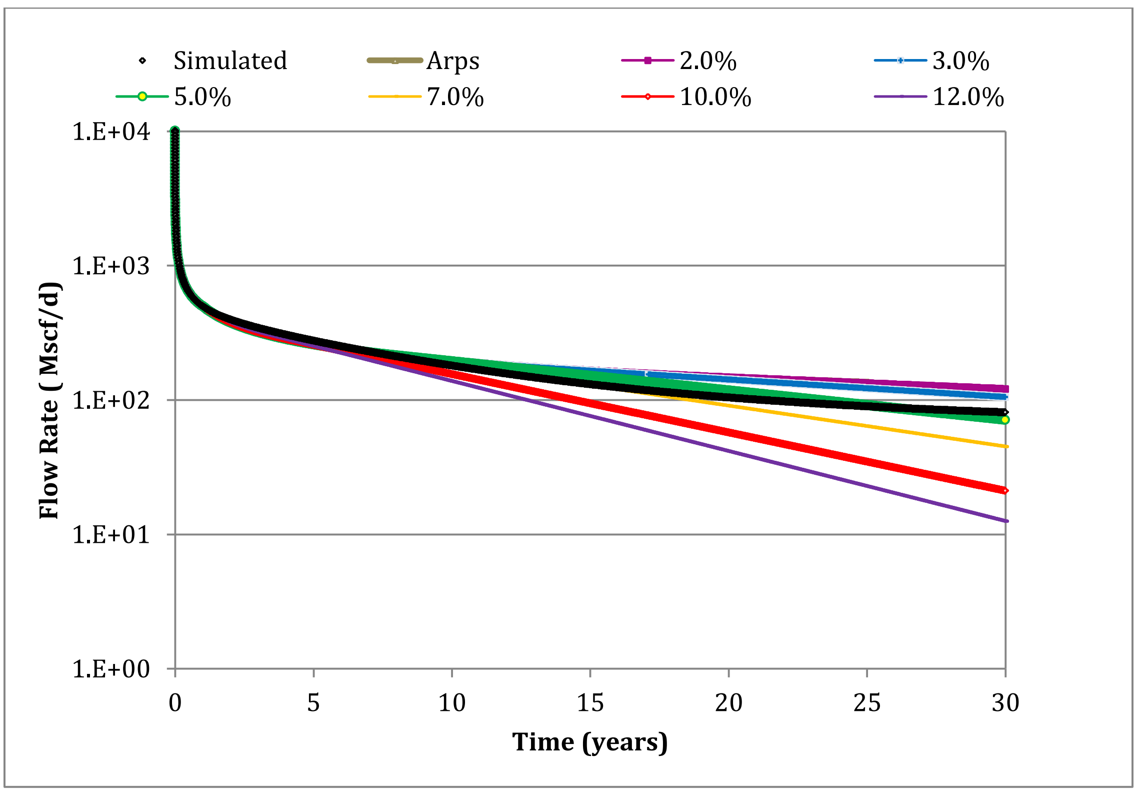

Figure 30: Comparison of simulated and projected rate-time profiles for different minimum terminal decline rates. Forecast is made using one year of production history for the vertical, layered fractured well -base case.

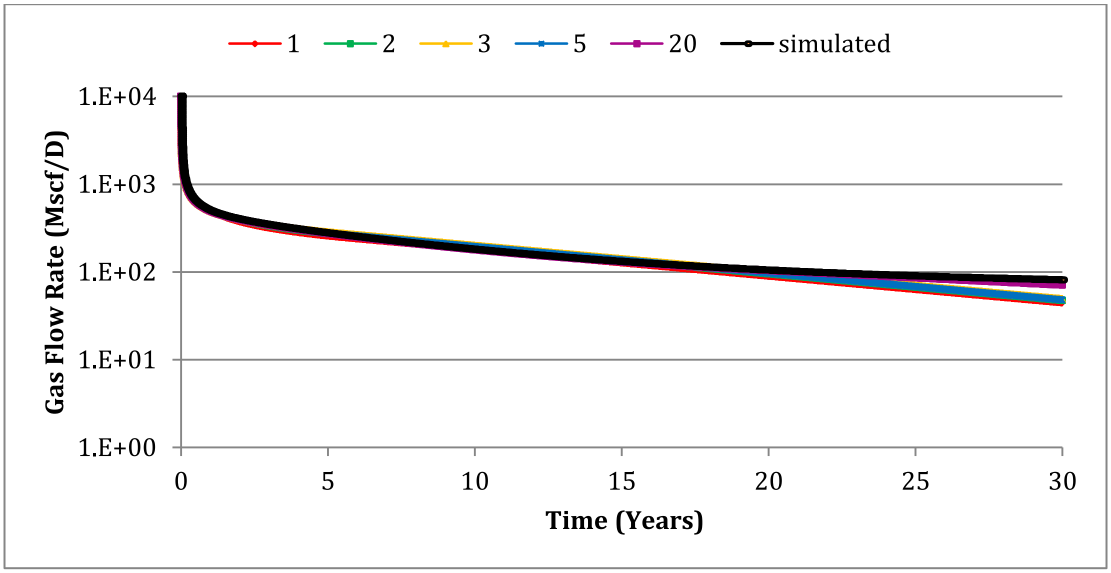

Figure 31: Comparison of simulated and projected rate-time profiles for vertical, layered fractured well base case for increasing quantities of production history. Minimum terminal decline rate is 7%.

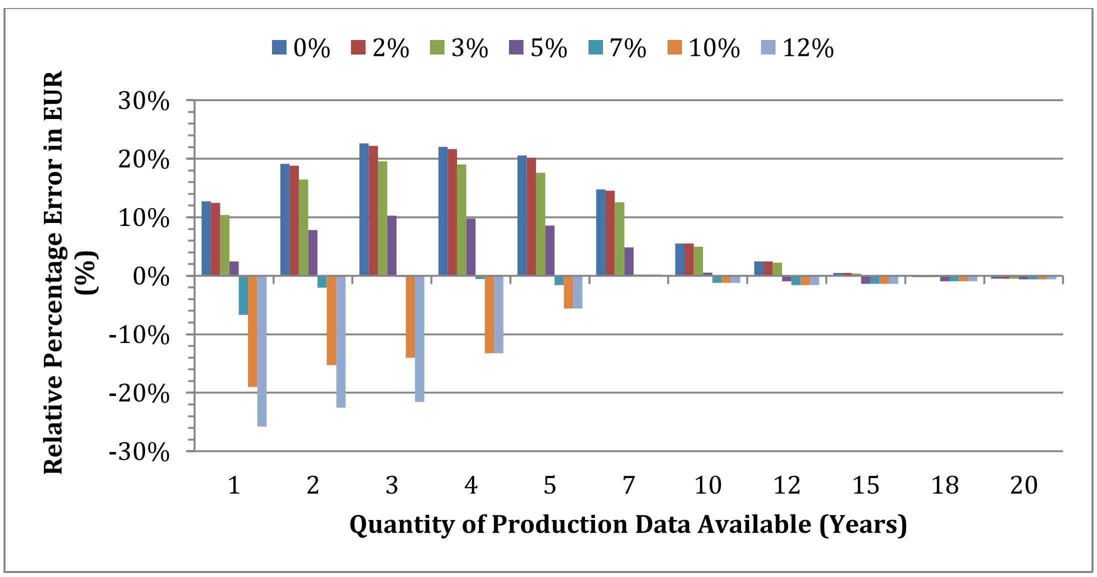

Figure 32: Base case for vertical fractured layered wells-Relative percentage error in EUR evaluated for different minimum terminal decline rates and increasing quantities of data.

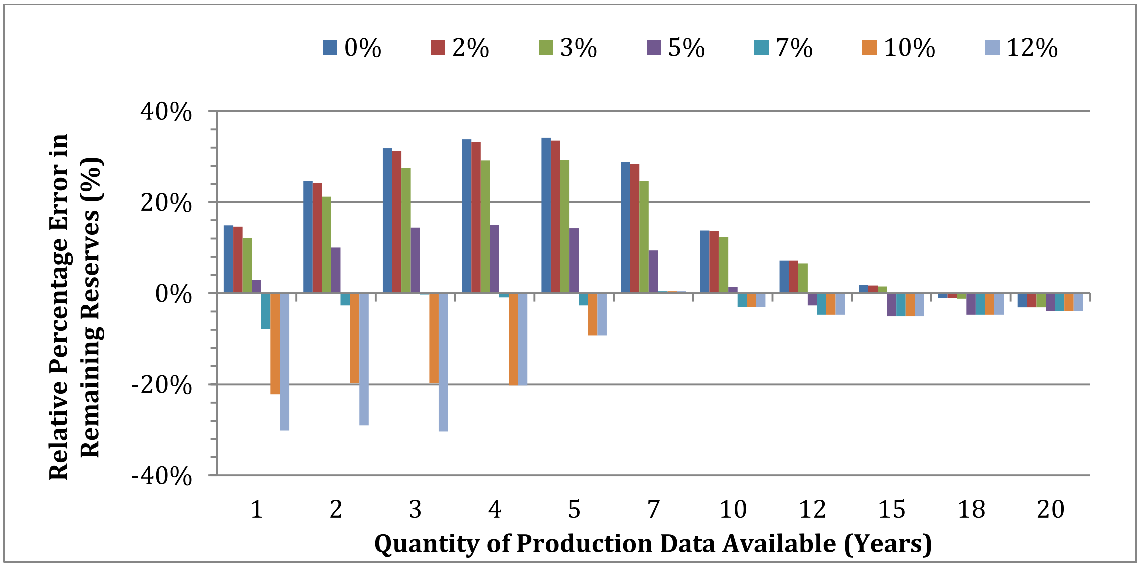

Figure 33: Base case for vertical fractured layered wells- relative percentage error in the remaining reserves evaluated using different minimum terminal decline rates and increasing quantities of production history.

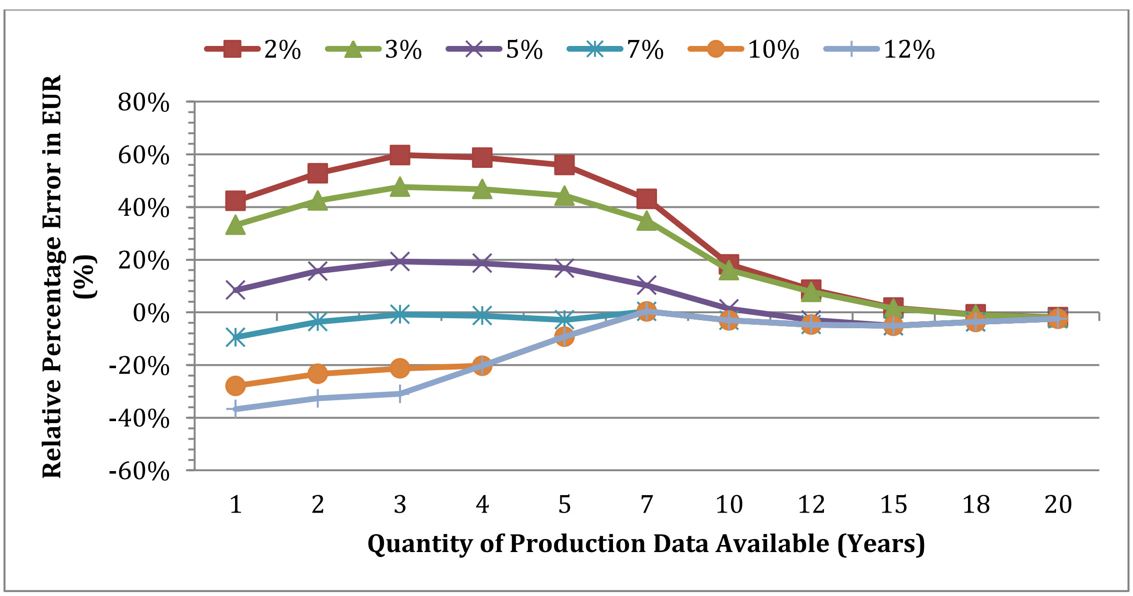

Figure 34: Base case for vertical fractured layered wells- percentage error in the remaining reserves for the exponential portion of forecast for different minimum terminal decline rates and increasing quantities of production history.

Similar trends to those observed for the previous completion type can be noted with respect to Figures 32 and 33. On the basis of the plot in figure 34, which describes the error due to the imposition of different minimum declines for increasing production history, it is evident that for simulated production profile for the base case, the most appropriate minimum terminal decline is 7% since this curves lies closest to zero.

3.2 Systematic Study of Vertical Fractured Layered Wells

For the development of the systematic study, properties which affect well performance were varied within the confines likely to be observed in the vertical fractured layered reservoirs. This study quantifies the range of errors that can be encountered by varying key properties of the base case and analyzing these profiles using the minimum decline rate which was most appropriate in the base case (7%). Selected properties for variation, the base case, lowest and highest value for the selected property are tabulated in Table 6. Selected properties include fracture half length, well spacing, dimensionless fracture conductivity and horizontal permeability anisotropy.

For each production profile, forecasts are generated with the benefit of increasing production history and the results for the relative error in EUR and in remaining reserves evaluated at the 30 year using a minimum terminal decline rate of 7% are presented below.

Table 6: Systematic Study of Vertical Fractured Layered Wells

Variations of Selected Properties

Property	Base	Minimum	Maximum
Well Spacing (acres)	320	80	Infinite
Dimensionless Fracture Conductivity (FcD)	300	0.01	Infinite
Fracture Half Length (ft)	700	50	1500
Kx/ky	1	0.1	20

3.2.1 Well Spacing

Throughout the life of the reservoir, wells have been drilled on ever decreasing well spacing. The drainage area of the wells inevitably affects the decline profile. As such the ability to predict the EUR and remaining reserves of these wells using the terminal minimum decline rate method (7%) has been studied. The resulting plots of relative error in EUR (Figure 35) and the relative error in relative error in remaining reserves (Figure 36) show decreasing errors with increasing production history utilized to make the predictions for well spacing.

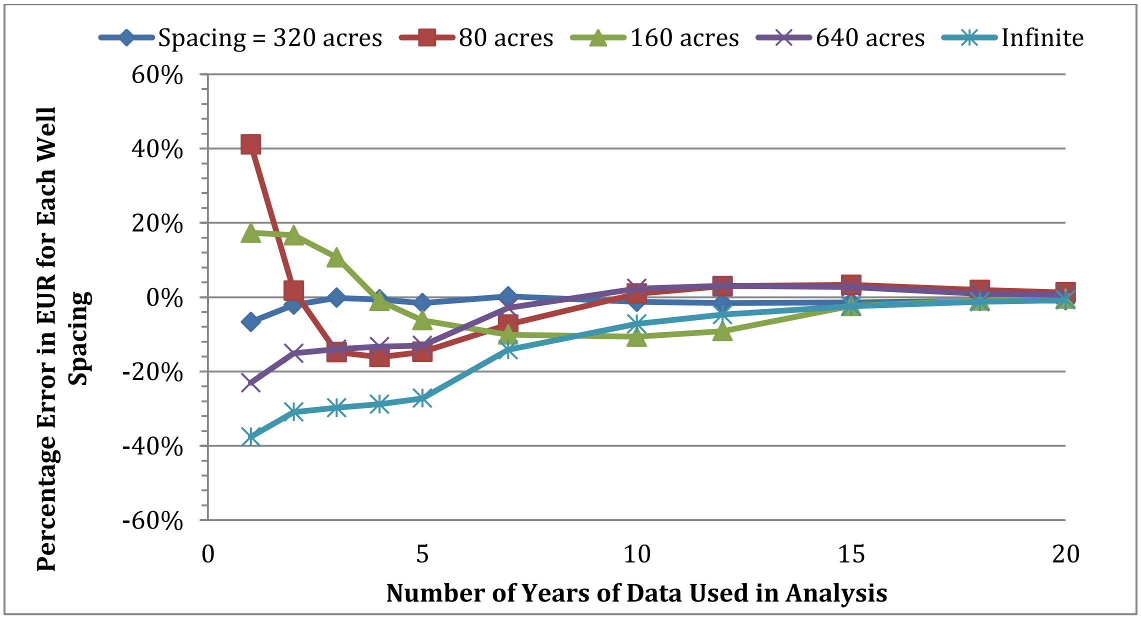

Figure 35: Vertical fractured layered wells-Variation in error in EUR for different well spacing and increasing production data, D_{min} = 7%.

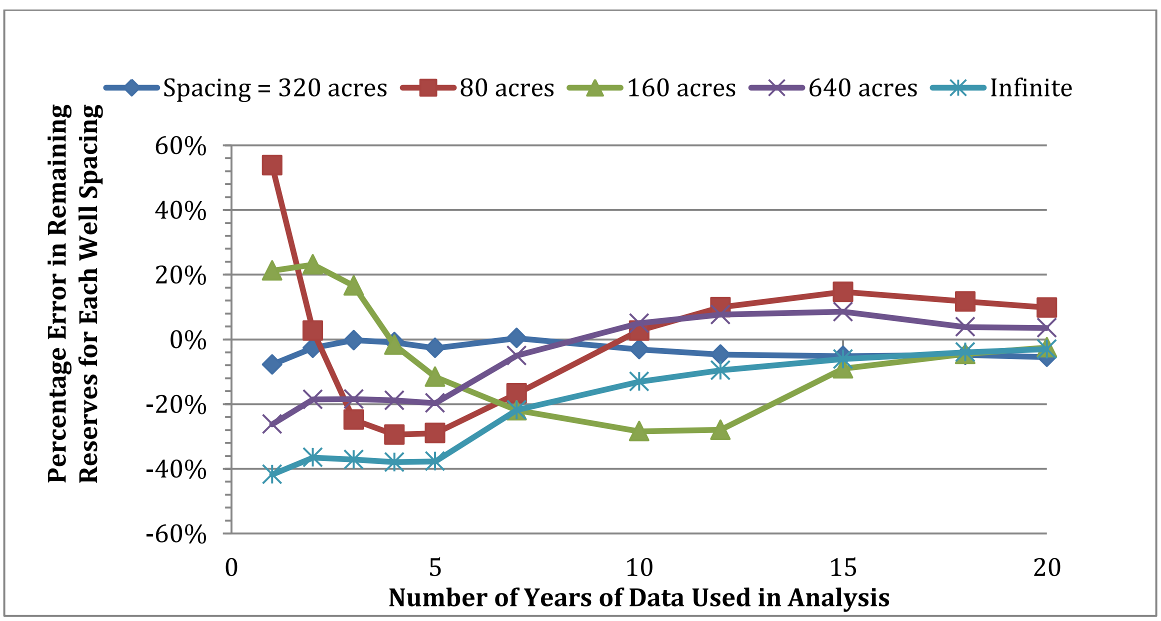

Figure 36: Vertical fractured layered wells- Variation in error in remaining reserves for different well spacing and increasing production data, D_{min} = 7%.

3.2.2 Dimensionless Fracture Conductivity (FcD)

The variation of dimensionless fracture conductivity is achieved, as in the case of the horizontal wells with multiple fractures, by changing the fracture conductivity. The base case F_{cD} is 300 and the variation increases from a minimum value of F_{cD} = 0.1 to a maximum of infinite conductivity. The evaluation of relative percentage error in EUR resulting from the rate-time determination of Arps hyperbolic fit and the application of a minimum terminal decline of 7% is shown below and is followed by the similar graph for remaining reserves.

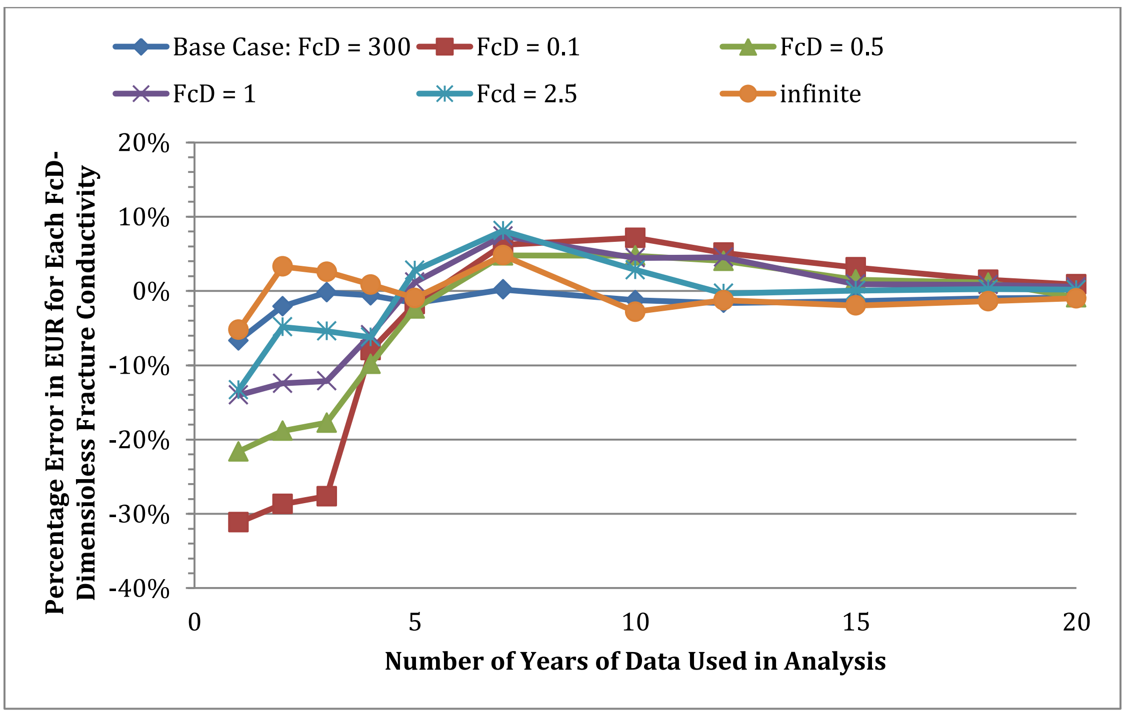

Figure 37: Vertical fractured layered wells-Variation in error in EUR for different FcD-dimensionless fracture conductivity and increasing production data. D_{min} = 7%.

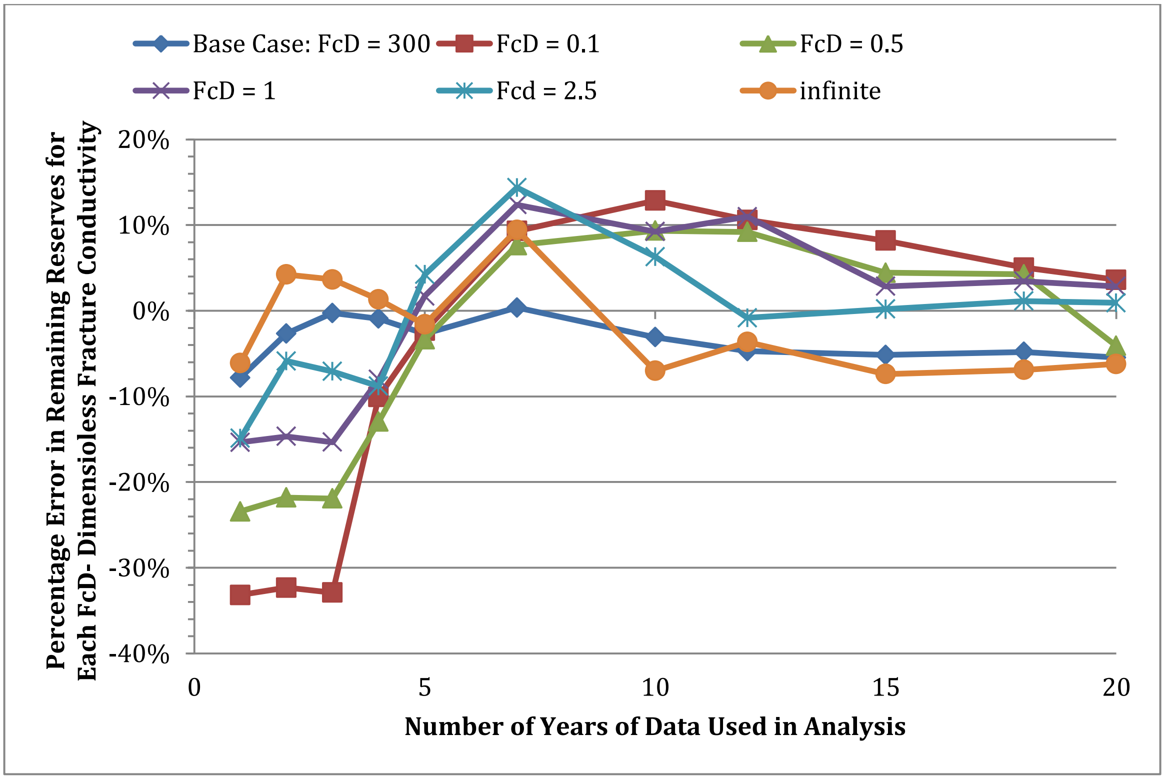

Figure 38: Vertical fractured layered wells-Variation in error in remaining reserves for different FcD- dimensionless fracture conductivity and increasing production data, D_{min} = 7%.

3.2.3 Fracture Half Length (Xf)

The variation the fracture half-length covers the range of 50 feet to 1500 feet and represents the distance from the vertical wellbore to which the fracture extends. For increased fracture length more of the reservoir is directly exposed to the fracture and as such larger fracture half-length translate into larger EUR. The variation in half-length produced the following trends on Estimated Ultimate Recovery (Figure 39) and in Remaining Reserves (Figure 40).

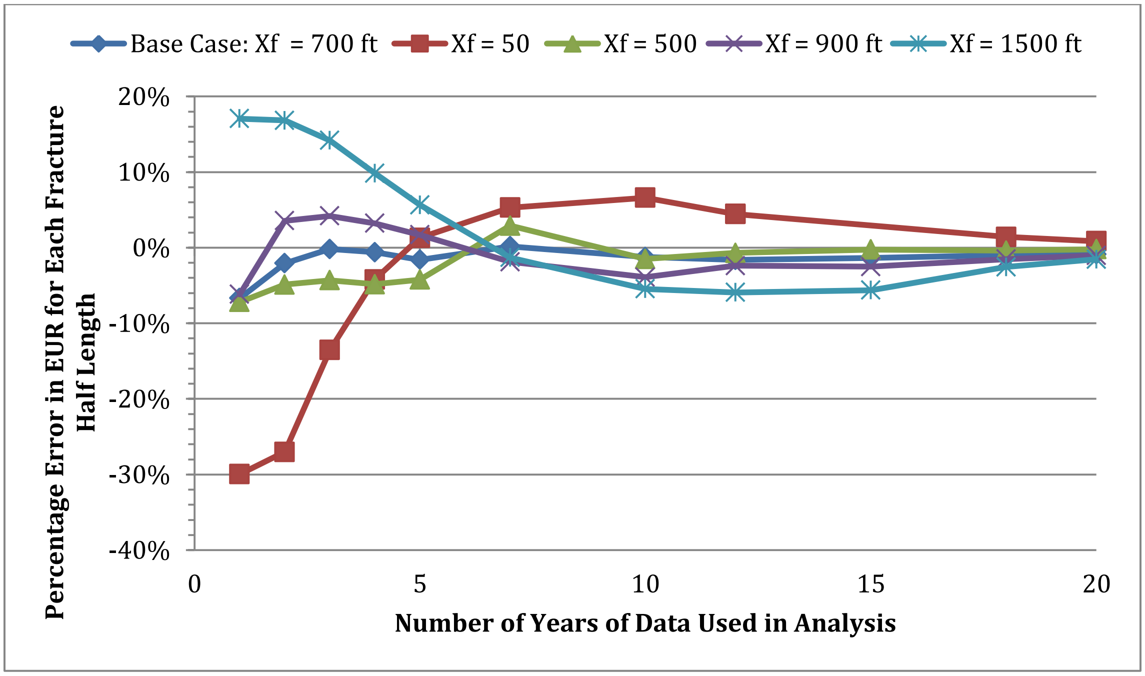

Figure 39: Vertical fractured layered wells-Variation in error in EUR for different fracture half-length and increasing production data, D_{min} = 7%.

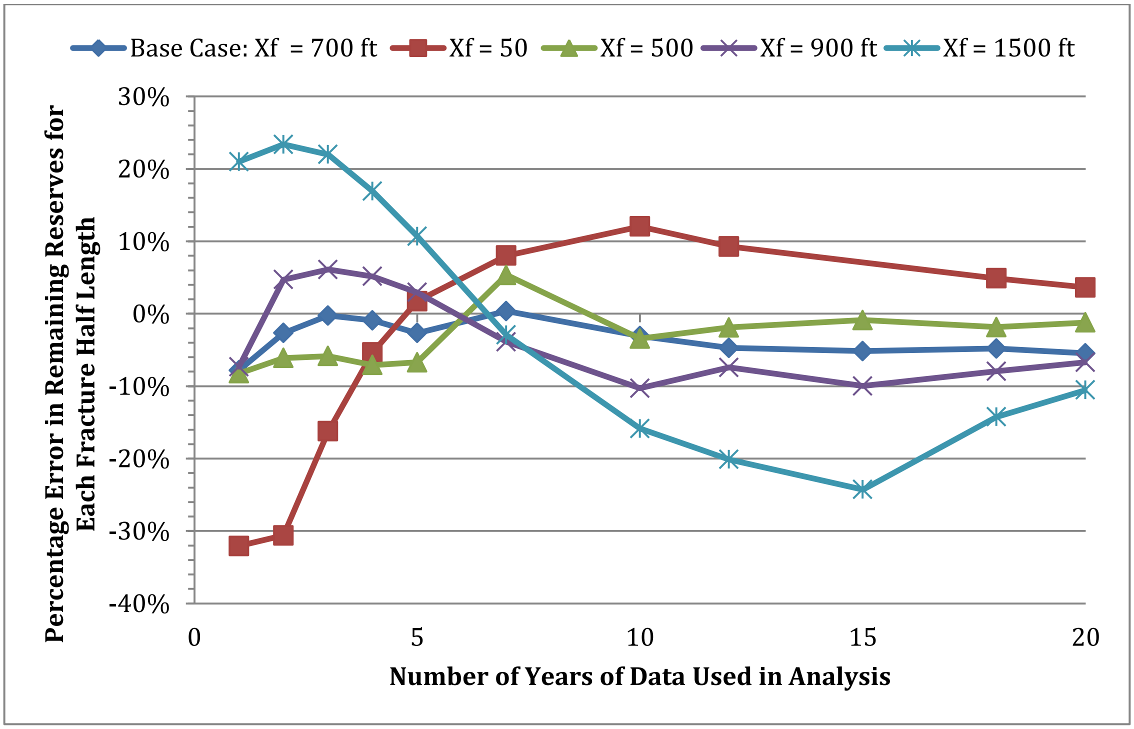

Figure 40: Vertical fractured layered wells- Variation in error in remaining reserves for different fracture half-lengths evaluated for increasing production history, D_{min} = 7%.

3.2.4 Orthogonal Horizontal Permeability Anisotropy

The variation of ratio of permeability anisotropy in the direction parallel to the fracture is simulated by varying the extents (distance of east boundary from west boundary) of the reservoir while maintaining the same area (well spacing). The desired ratio of the distance in the x direction to that in the y direction must be the same as the square root ratio of the permeability anisotropy ratio kx/ky.

The results for these variations are shown in Figures 41 (Estimated Ultimate Recovery) and Figure 42 (Remaining Reserves). The errors seen in these variations are significantly smaller than those observed in the previously presented variations. All of the errors in EUR are within +/-10% while those for remaining reserves are within +/-18%.

From the systematic study, the errors from evaluating some of the generated cases are quite similar to those which result from of the base case, however but the final error ranges from study is greatly influenced by the few cases which behave quite differently.

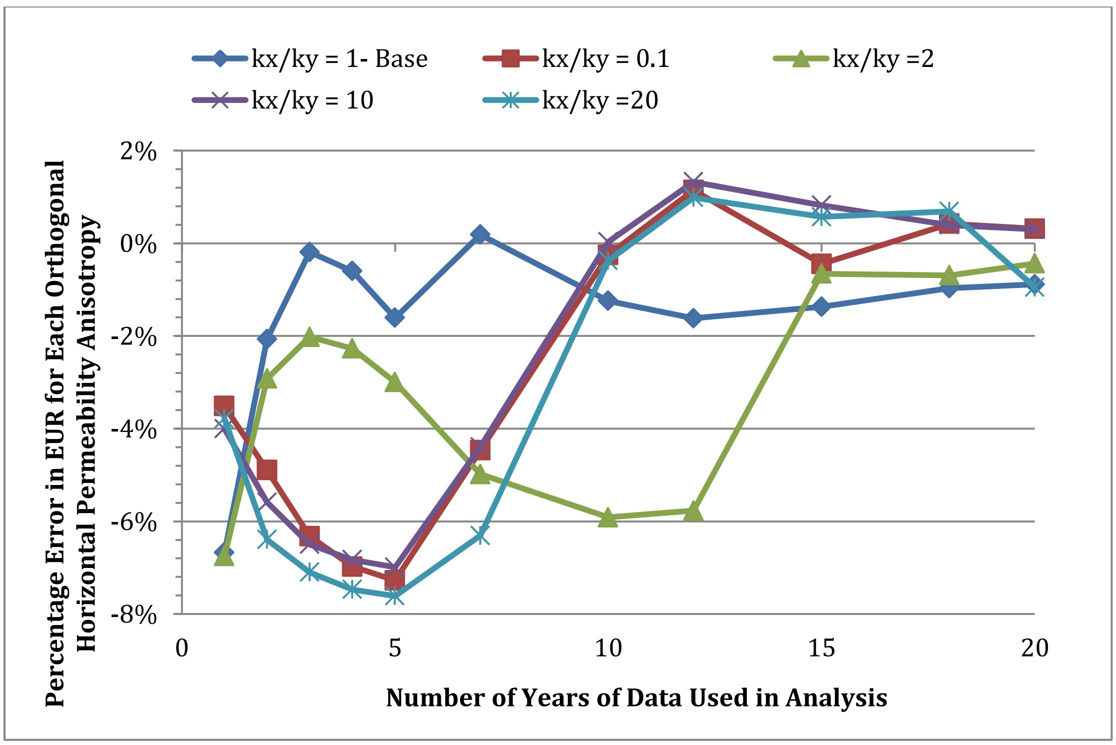

Figure 41: Vertical fractured layered wells-Variation in error in EUR for different orthogonal horizontal permeability anisotropy and increasing production data, D_{min} = 7%.

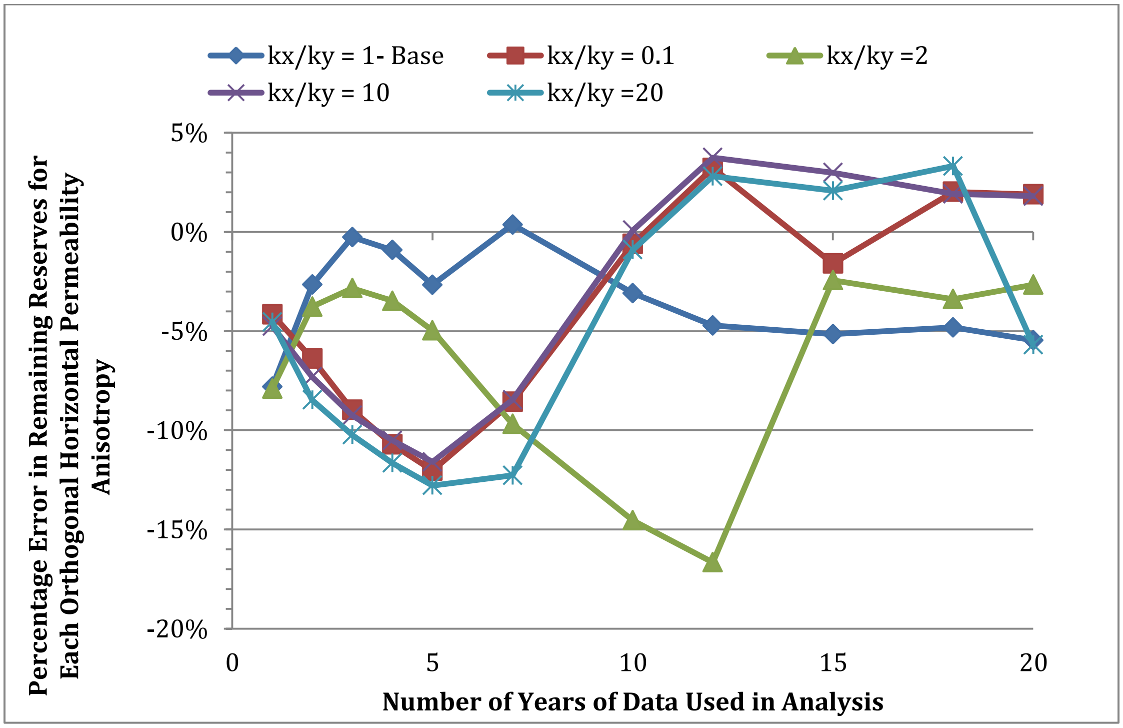

Figure 42: Vertical fractured layered wells-Variation in error in remaining reserves for different orthogonal horizontal permeability anisotropy and increasing production data, D_{min} = 7%.

Similar to what was found in the systematic study of MFHW is the finding that errors calculated with the benefit of small quantities of data tend to be quite high, however increasing the production history considered significantly reduces the errors.

In summary a decline rate of 7% is representative for the evaluation of the systematic study of vertical layered fractured wells. The errors in EUR and remaining reserves are:

- Estimated Ultimate Recovery:
    - 2 years +/- 40%
    - 10 years +/- 15%.
    - 20 years +/- 8 %
- Remaining Reserves:
    - 2 years +/- 50%
    - 10 years +/- 30
    - 20 years +/- 12%

3.3 Real Carthage Cotton Valley Well: Vertical Fractured Layered Wells.

Several Carthage Cotton valley wells were analyzed but the example of Conoco Operated 42-365-31921 is chosen for illustration because it was one of the wells used for matching the base case for the simulation study of vertical fractured layered reservoirs. A tabulated list of some of the wells used in arriving at the conclusions is supplied in appendix B.

3.3.1 Conoco Operated Panola County Well. API 42-365-31921

The real well data presented in this section comes from Conoco Operated 42-365-31921, first drilled and completed in January 1989. Some of the initial production data was erratic and so this data was eliminated from the analysis. After four months of production however the performance stabilized and a production profile could be identified. Thus this real well production was analyzed from May 1989 until the well was recompleted in October 2006. In October 2006 the cumulative production for the well was 1.623 BCF and this is used as the "EUR" in the evaluation. After recompletion the well remained on production until September of 2008 when it was finally shut-in. The production between the perceived stabilization point and the assumed recompletion was analyzed. The initial cumulative production was of course re-added to achieve the final cumulative production prior to the re-stimulation.

The full production history for the well is shown below in Figure 43. A look at the unedited data will show that there are alternative ways to approach the evaluation. Reasonable arguments can be made for eliminating up to 2.75 years of production data and starting the analysis at that point since the increase in production may be attributed to re-stimulation work done on the well. However, in the absence of a well history that can confirm this well work, the decision was made to neglect only the first four months of production history. If the well was shut-in for period of time this could also result in the peak of production seen at 2.75 years. Another and perhaps the greater consideration is the fact that it is preferable to use as much of the production history as possible once a consistent production trend can be interpreted by eliminating a few points. The edited production profile is show in Figure 44 and the data points which were not considered in the analysis are highlighted in red.

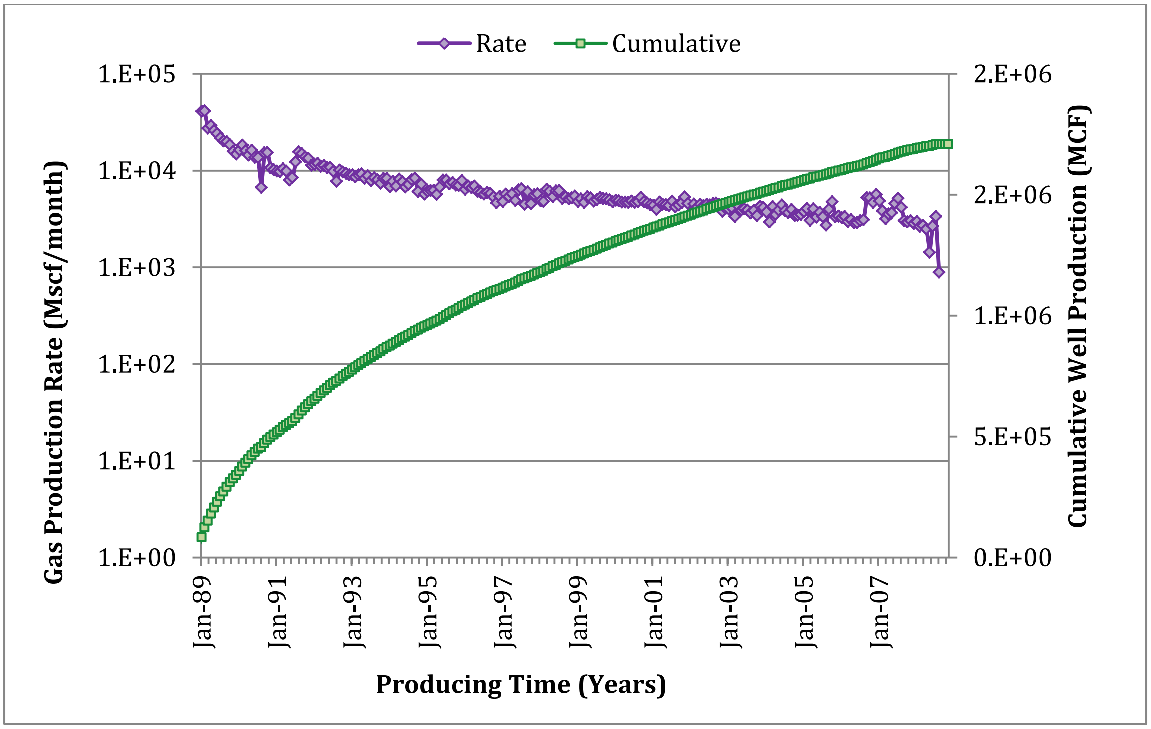

Figure 43: Complete production history for Conoco operated well API: 42-365-31921.

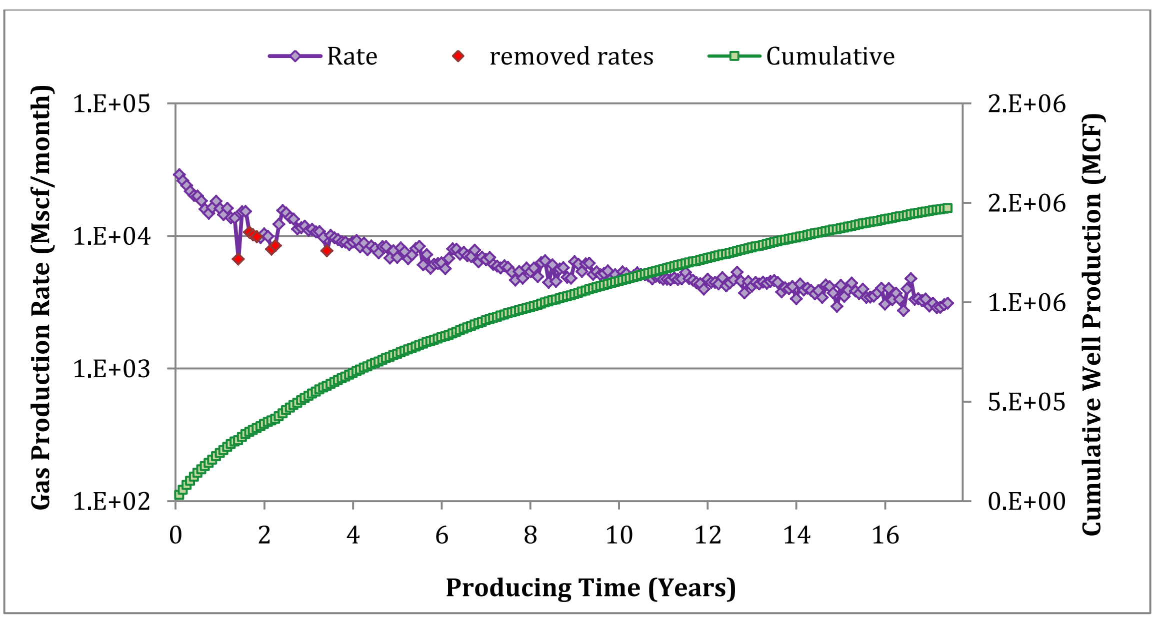

Figure 44: Edited production history for Conoco operated vertical fractured layered Carthage Cotton Valley well API: 42-365-31921.

Rate- time analysis of the well was performed at the end of years 1, then 2, then 3, then 4, then 5, then 7, then 10, then 12, then 15. Figure 45 below shows the rate time match of the Arps hyperbolic equation for the production history up to the end of the first year. This was achieved using solver. The minimization function matches the trend as well as the last recorded production rate. Production data subsequent to this point is not considered in performing this match. The resulting rate-time, rate –cumulative production and cumulative production time forecasts for this fit are projected to the end of the well life at 17.75 years. These are shown as Figures 46, 47 and 48. This followed by Table 7 and Table 8 which summarize production volumes for the first year as well as the results for applying different minimum decline rates respectively.

These analyses illustrate what can be expected when making predictions using small quantities of production history. This is that the predictions can tend to overestimate the known outcomes. This was also the findings of the simulated study. In the evaluation of 42-365-31921 the Arps hyperbolic model gives large EUR of 2.09 BCF at the end of the well life of 17.75 years. Applying the minimum terminal decline rates compensate for this over-prediction but in early times this compensation- of the minimum decline rate method- may not be enough. The minimum decline rates from analyzing the simulated data was 7% and by applying this decline, the predictions at the end of the first year show an error in the EUR is 19.71%. The error in the remaining reserves prediction is 25.95%.

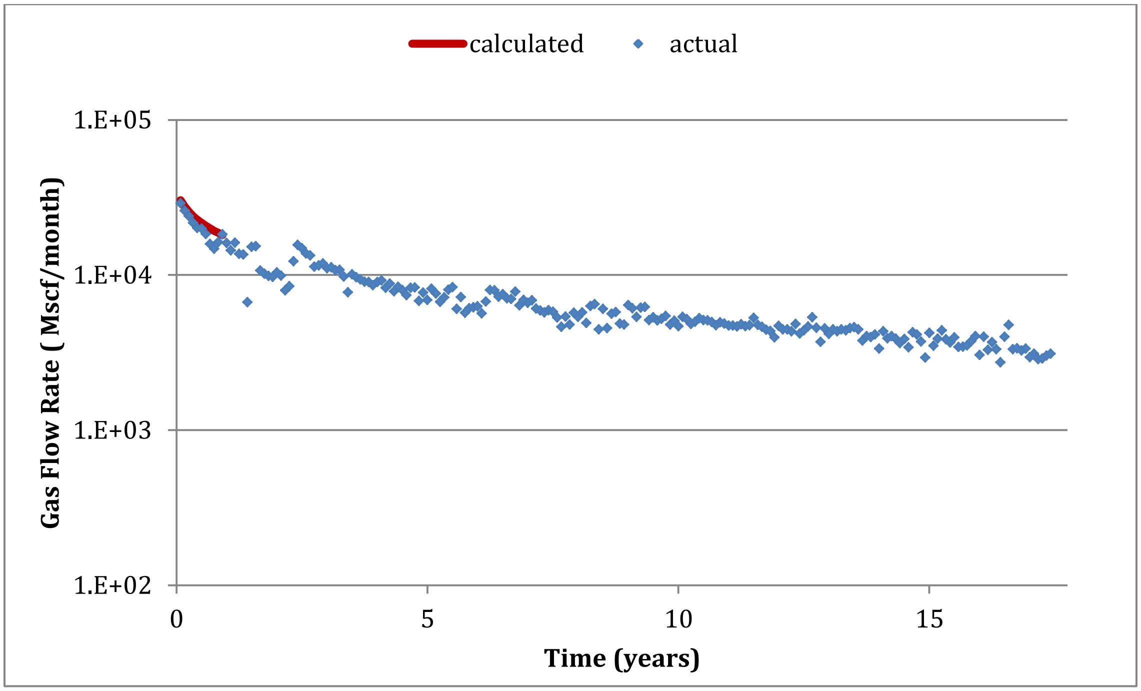

Figure 45: Arps hyperbolic rate-time match for one year of actual production history. Actual data points are shown in blue data points and the Arps hyperbolic fit is overlaid in as a red line. Arps parameters are qi= 24000 MCF/month, b = 2.58 and D_i = 0.76 yr^{-1}.

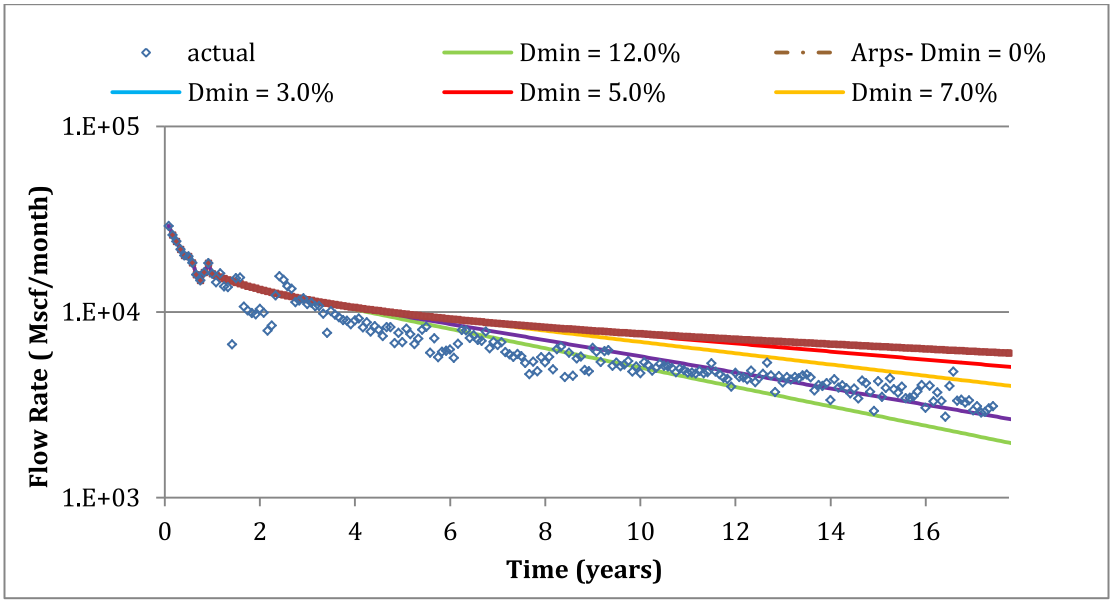

Figure 46: Comparison of actual and forecasted rate -time relationship for one year of production history from Conoco operated well (API: 42-365-31921) using varying minimum terminal decline rates.

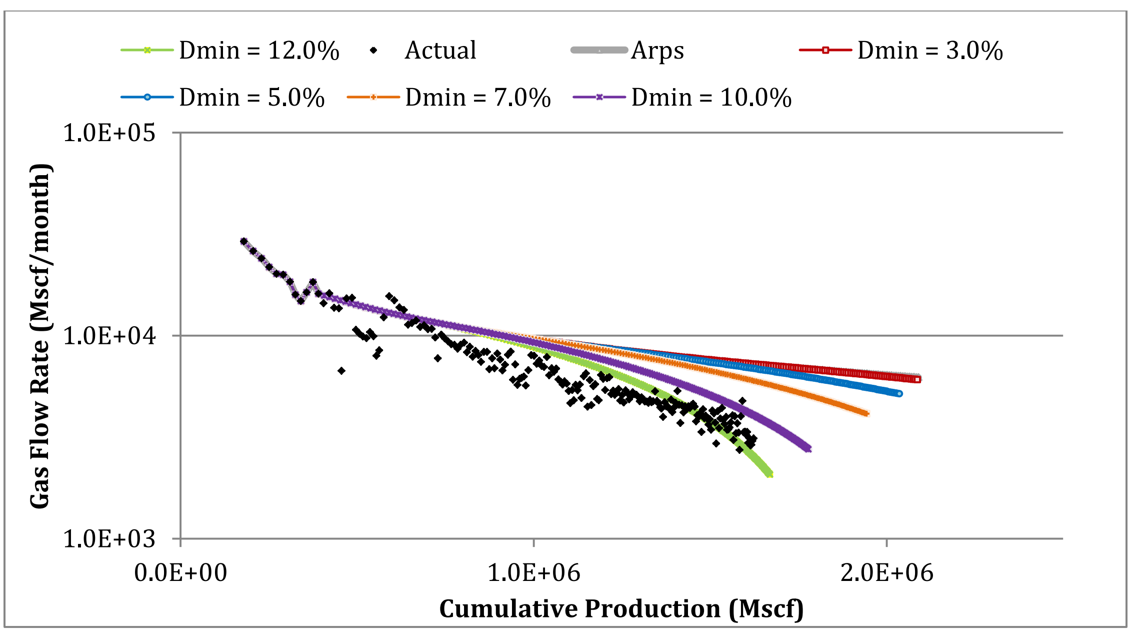

Figure 47: Comparison of actual and forecasted rate –cumulative production relationship for one year of production history from Conoco operated well (API: 42-365-31921) using varying minimum terminal decline rates.

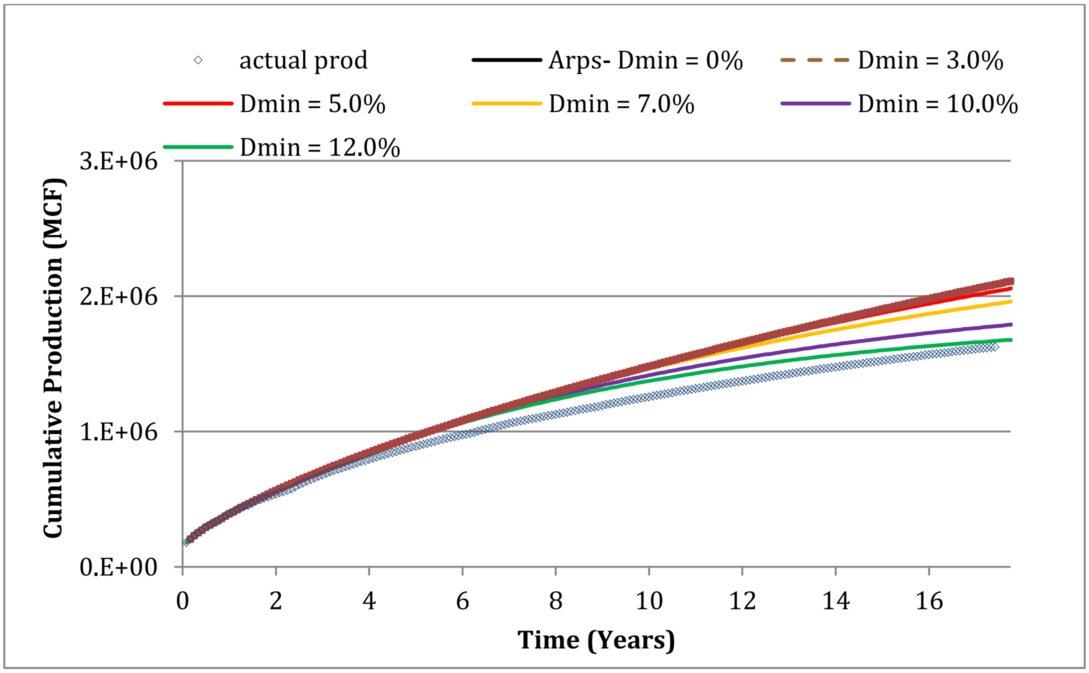

Figure 48: Comparison of actual and forecasted cumulative production -time relationship for one year of production history from Conoco operated well (API: 42-365-31921) using varying minimum terminal decline rates.

Table 7: First Year of Actual Production Performance for 42-365-31921(4)

Actual	1.6234
Time (Years)	1
Cum Prod	0.3913

Table 8: Comparison of Actual and Calculated Estimated Ultimate Recovery, Remaining Reserves and Associated Relative Percentage Error

Method of Analysis	Estimated Ultimate Recovery (EUR) , BCF	Error in EUR	Remaining Reserves	Error in Remaining Reserves
Actual	1.6234	-	1.2322	-
Arps	2.0900	28.74%	1.6987	37.86%
3.00%	2.0868	28.54%	1.6955	37.61%
5.00%	2.0361	25.41%	1.6447	33.48%
7.00%	1.9432	19.70%	1.552	25.95%
10.00%	1.7788	9.57%	1.3875	12.61%
12.00%	1.6698	2.85%	1.2785	3.76%

Continuation of the analysis for increasing quantities of data shows improvement in the accuracy of the predictions. The Arps Hyperbolic match obtained using seven years of data is shown in Figure 49.

With seven years of production data the relative errors in EUR and in Remaining Reserves are reduced to 1.47% and 4.22 % respectively. Similar plot illustrating forecasts for rate-time, rate-cumulative production and cumulative production time are shown as Figures 50, 51 and 52. The predictions from these plots all indicate that an appropriate minimum decline rate lies between 7% and 10% for this evaluation. This can be confirmed by matching the trajectory of real and projected data in Figure 55.

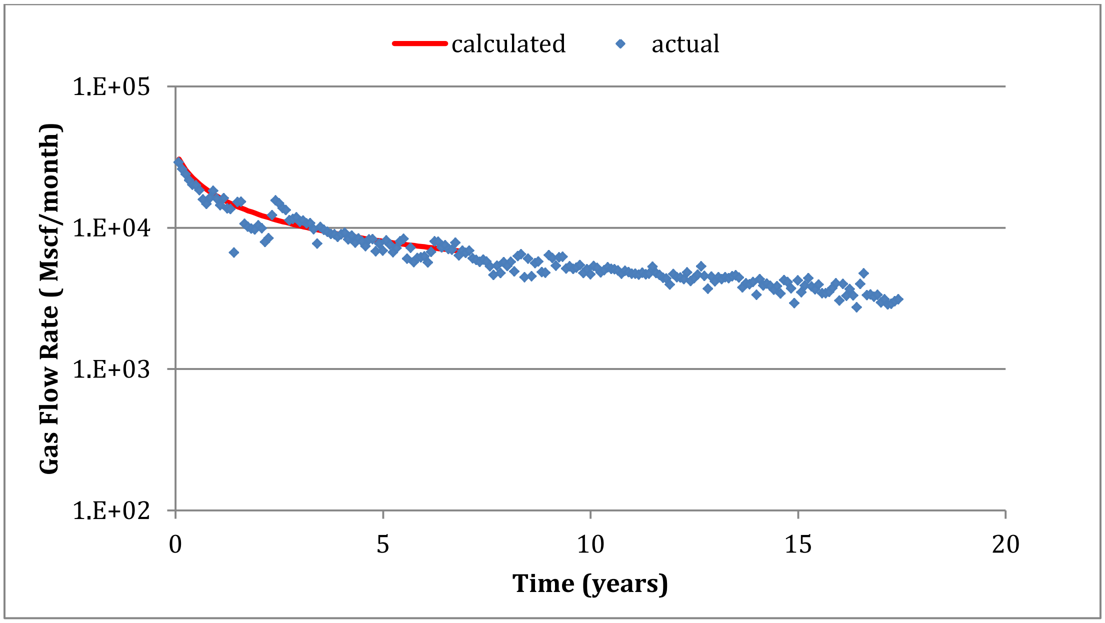

Figure 49: Arps hyperbolic match of real well data from Conoco operated 42-365-31921 using seven years of production history and different minimum terminal decline rates. Arps hyperbolic match is q_i = 2400 MCF/month, b= 1.879, D_i = 0.779 yr^{-1}.

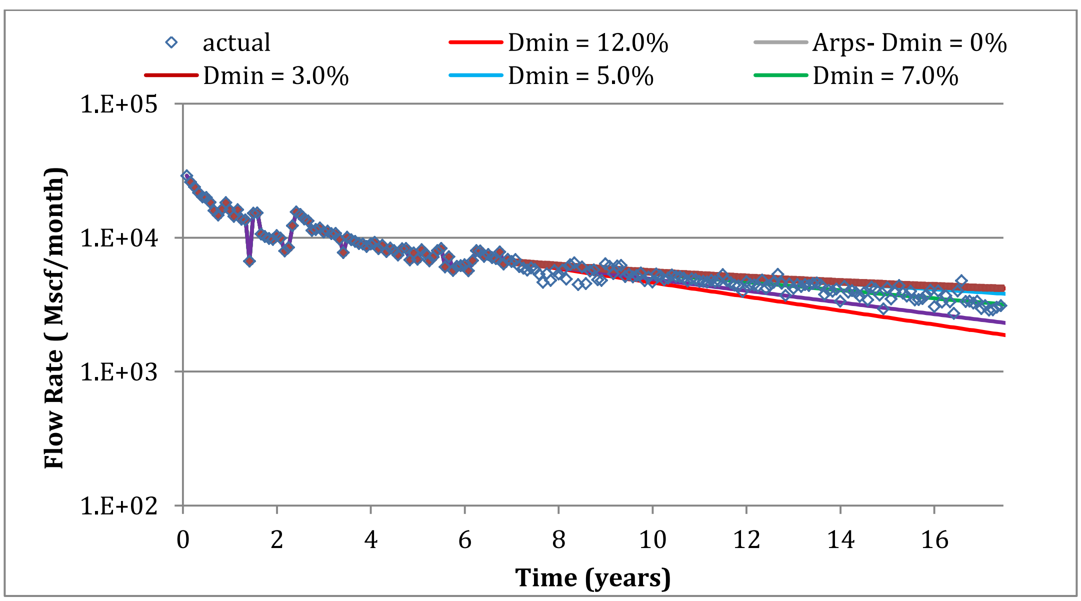

Figure 50: Comparison of actual rate -time data with forecasts using seven years of production history and different minimum terminal decline rates for Conoco operated well API: 42-365-31921(4).

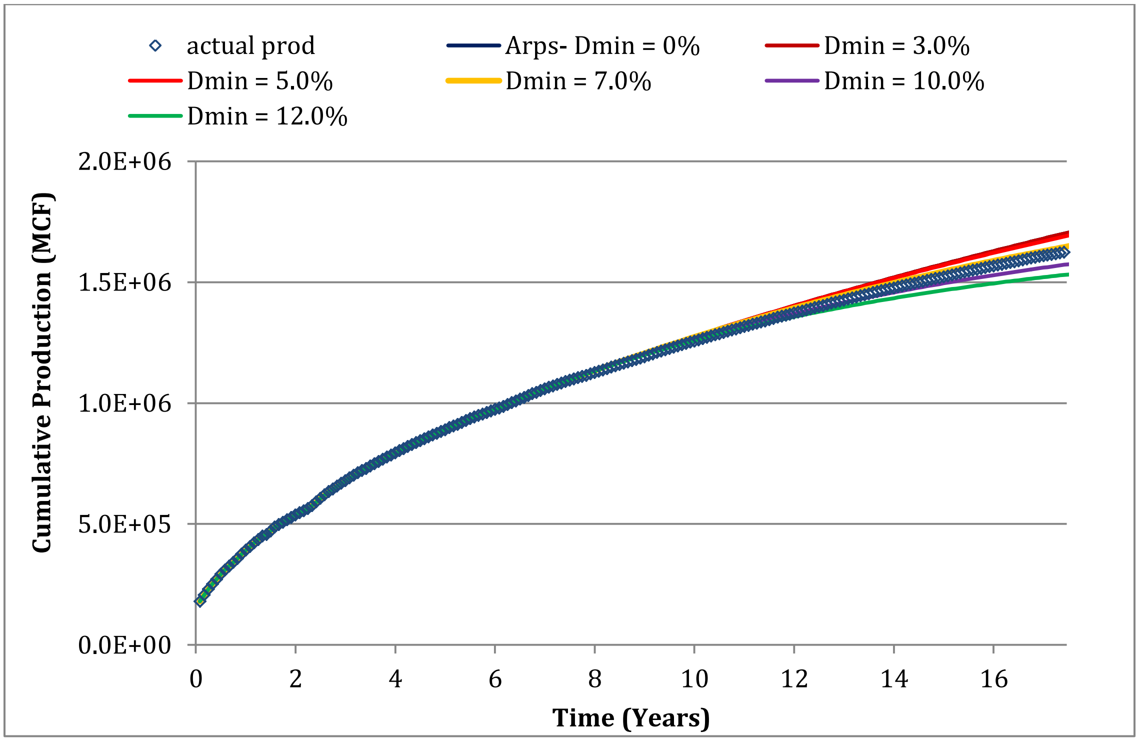

Figure 51: Comparison of actual cumulative production -time data with forecasts using seven years of production history and different minimum terminal decline rates for Conoco operated well API: 42-365-31921(4).

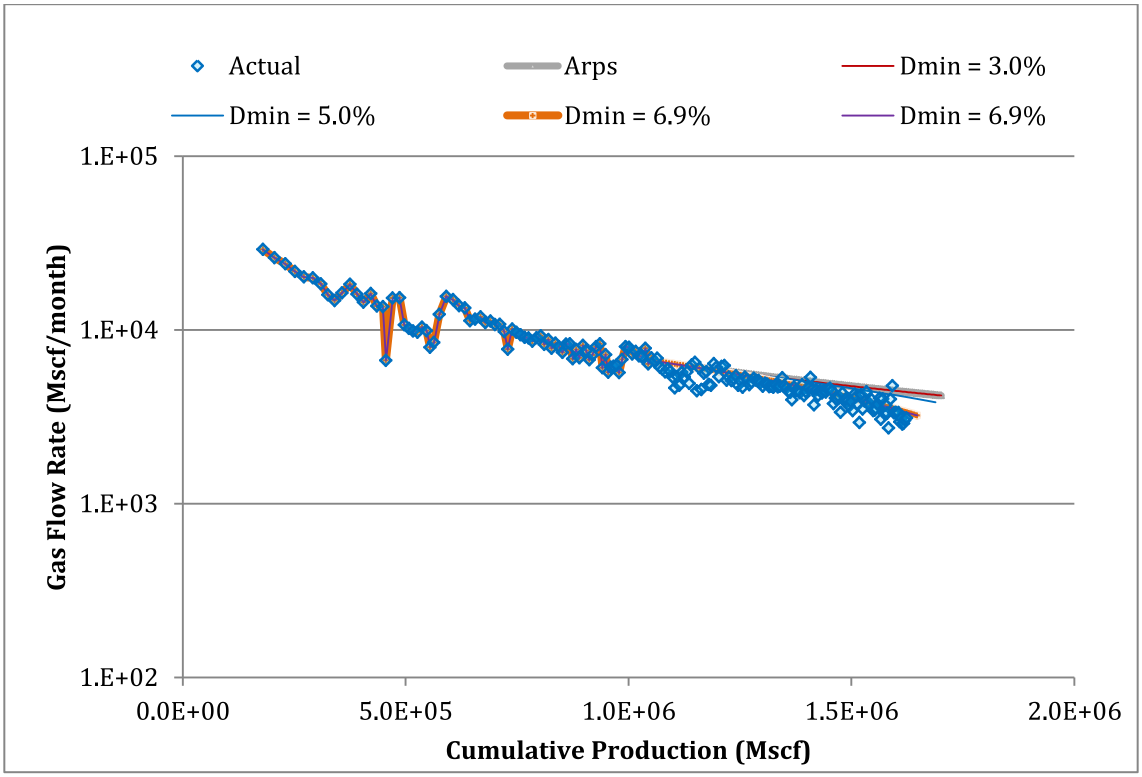

Figure 52:Comparison of actual rate –cumulative production data with forecasts using seven years of production history and different minimum terminal decline rates for Conoco operated well API: 42-365-31921(4).

The fact that is well has produced to abandonment make it a good candidate from which determine the minimum terminal decline rate. Figure 53-55 summarize the findings for the analyzed well life. Figure 53 shows the relative percentage error in the calculated EUR for differing decline rates evaluated to a known EUR of 1.623 BCF. In some cases the value of the error is positive indicating over-prediction and in others it is negative (under-predicting). The location of the transition is the minimum terminal decline which would perfectly predict reserves for that particular analysis. As an example in year 4 (results presented above), forecasts for 0%- 7% all over-predict reserves while decline rates of 10%- 12% under-predict reserves indicating that for this analysis, the application of some decline rate between 7% and 10% would yield a perfect prediction of reserves.

Figure 54 presents a similar plot for relative percentage error in remaining reserves for increasing production time and differing terminal minimum decline rates. Figure 55 presents the volumes of actual remaining reserves compared to those predicted by the use of the varying minimum terminal decline rates. From the analysis of this well it is concluded that an appropriate decline rate is minimum terminal decline rate is between 7% and 10%.

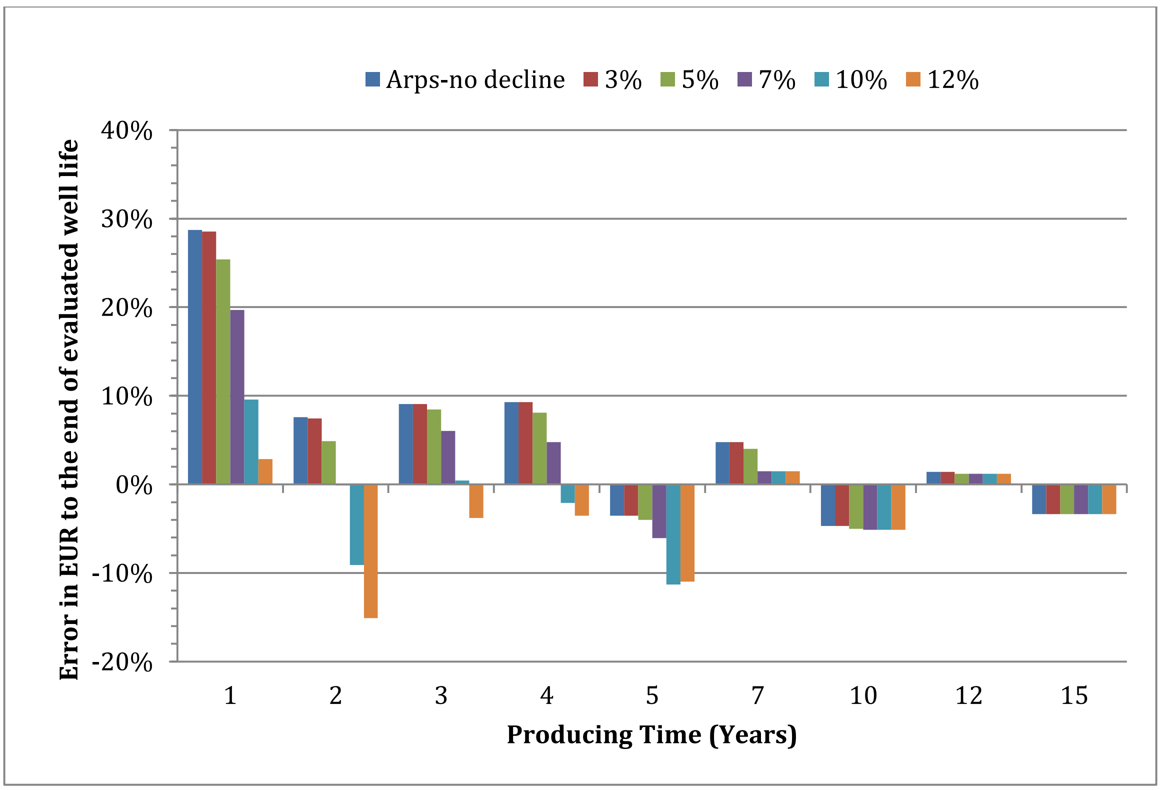

Figure 53: Variation in error in EUR prediction for Conoco operated well 42-365-31921. Well life is 17.75 years.

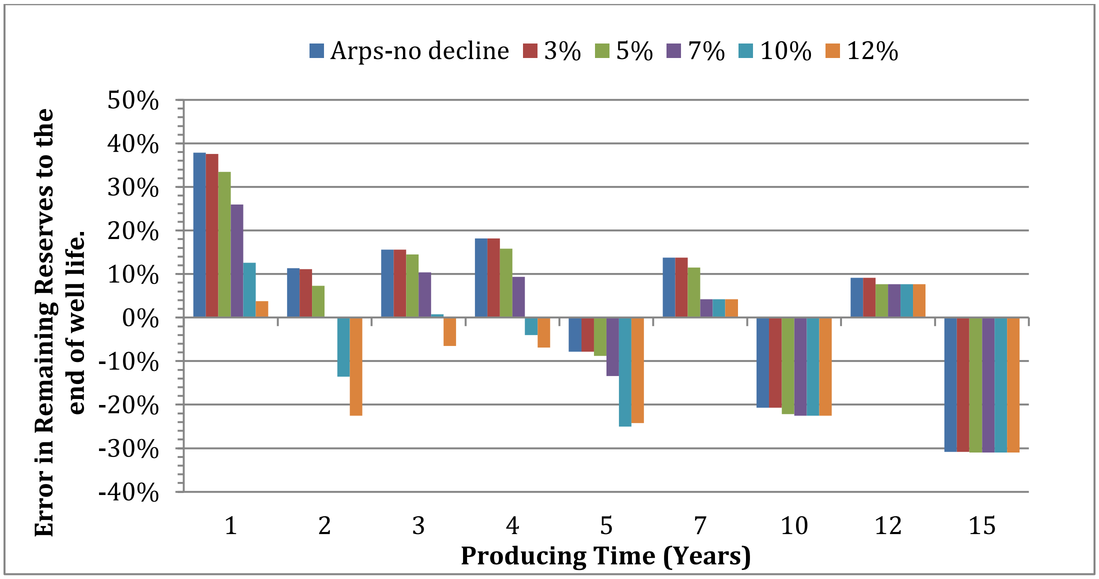

Figure 54: Variation in error in remaining reserves prediction for Conoco operated well 42-365-31921. Well life is 17.75 years.

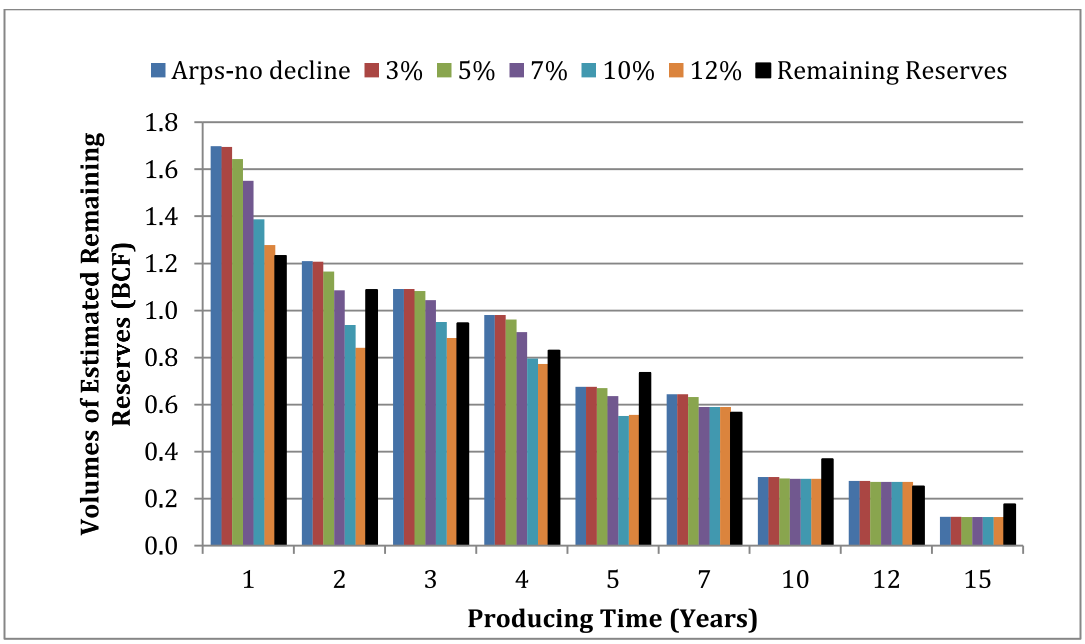

Figure 55: Comparison of actual and calculated remaining reserves volumes for Conoco operated well 42-365-31921. The remaining reserves are plotted in the black bars and different minimum terminal decline rates are shown in other colors.

The reason for the uniform under-prediction of reserves in the years 5, 10 and year 15 relate to the scatter of the production data. The fit of the Arps hyperbolic equation in these cases is made based on data up to end of the analyzed time period. The influence of any subsequent data is not considered. Furthermore, greater consideration is given to fitting the most recent data. A match of production data for ten years of history is presented in Figure 56. From the graphic it is clear that this match is a good fit with the most recent production data.

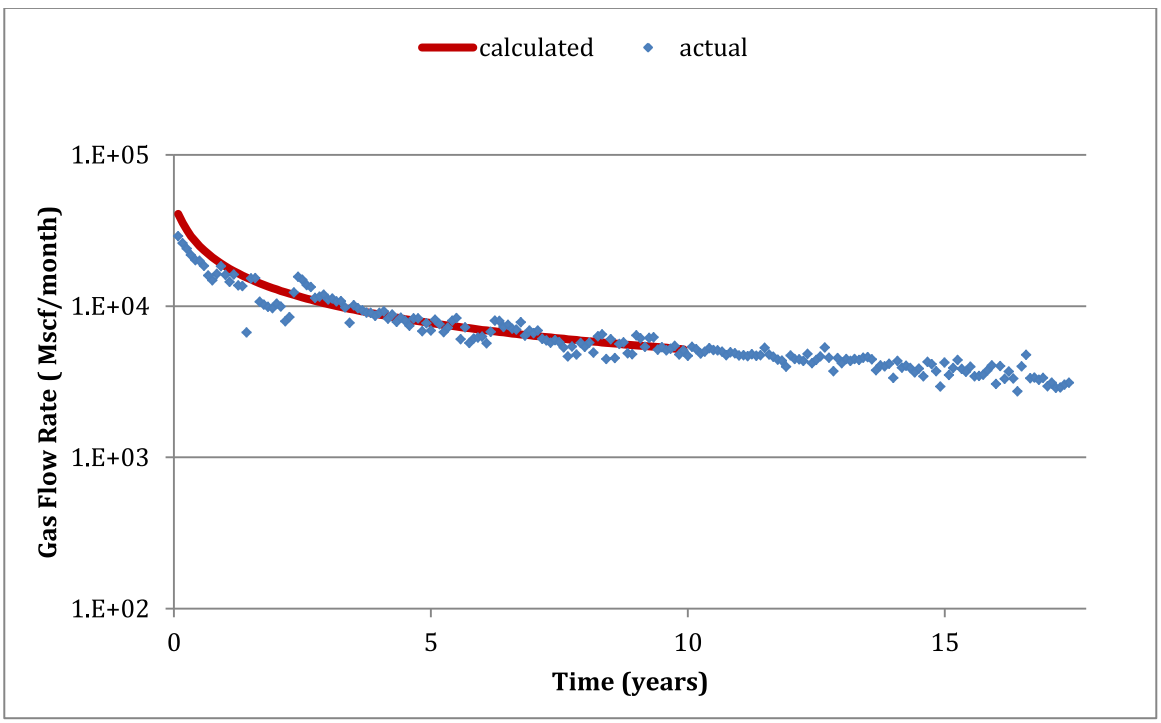

Figure 56: Arps hyperbolic rate-time match for 10 years of actual production history for well 42-365-31921. The Arps hyperbolic match parameters are q_i = 29.008, b= 1.662 and D_i = 1.03 yr^{-1}.

Conoco operated well API: 42-365-31921 is typical of many of the abandoned wells evaluated for the Carthage Cotton Valley field. Often the early production data from this field is erratic in some cases due to well loading, frequent recompletions, shut-in periods, combinations of the aforementioned or for unexplained reasons. Several wells downloaded from drilling info barely have significant periods with consistent production profiles suitable for analysis. Some of the evaluated wells are tabulated in appendix B.

The evaluation of this presented well and others confirm that for the Carthage Cotton Valley field wells with similar properties are likely to have a minimum terminal decline rate is between 5% and 10%.The evaluation of simulated base case for vertical fracture layered wells showed that an appropriate minimum terminal decline rates if 7%.

This result can provide guidance for the assessment of real Carthage Cotton Valley wells if the minimum terminal decline rate is used for forecasting. Even in cases with frequent well work-overs and re-stimulations we at least know what an appropriate minimum terminal decline rate is likely to be. This is half the required components for the successful application of the minimum terminal decline rate method. The other is the clear and consistent production profile. The clearer the trend and longer the evaluated production history the more accurate the forecast is likely to be.

IV. CONCLUSIONS

4.1 Conclusion

For the analysis of horizontal wells with multiple fractures in shale gas formation:

1. <u>Knowledge of decline rate and consistent production trend are essential</u>. There is insufficient data from Real Barnett Shale wells with new completion type – multistage fracture MFHW- to determine an appropriate minimum terminal decline rate. In the absence of suitable analogs for the determination of the minimum terminal decline rate it would be difficult to correctly apply the methodology. Knowing the minimum terminal is an essential ingredient for making successful predictions. Decline rates which are too low will over-predict reserves and the converse is also true. The evaluation of Devon operated 42-497-35635 shows at wide range of possible outcomes at the end of the 30 year well life for decline rates of 2% to 12%. The evaluation of Devon operated 42-497-32244 after 6 months and 5 years also illustrated the effect of inconsistent production trend.

2. <u>Good predictions for short time horizon are possible</u>. If the production history shows a clear and consistent trend, cumulative production for a short well life, such as six years, can be successfully predicted. Devon operated Wise County well API 42-497 35635 shows errors of between 1.5% and 7% for all applied decline rates used to predict the cumulative production at the 6th year. Also

evident is that in this early production life of 6 years the decline rate is still above 7 %.

3. Evaluation of base case for MFHW showed that an appropriate decline rate was 3%. Evaluation of synthetic data modeled after a MFHW from the Barnett shale has an appropriate minimum terminal decline is 3% for a well life of 30 years. This result is applicable only to wells with similar properties.

4. Evaluation of synthetic data give high errors at early times- Evaluation of the systematic study, using the terminal decline rate of 3% reveal that for variations of dimensionless fracture conductivity, fracture half length, fracture spacing and other sensitivities the errors in EUR and Remaining reserves at the 30th year are

    - Estimated Ultimate Recovery:
        - 2 years +/- 50%
        - 10 years +/- 12%.
        - 20 years +/- 3 %
    - Remaining Reserves:
        - 2 years +/- 80%
        - 10 years +/- 20
        - 20 years +/- 7%

In an environment where engineers are often required to predict performance with as little as 6 months of production history, the stated errors ranges provide note of caution if using small quantities of production history.

For the analysis of vertical fractured wells in layered formation:

5. <u>Good accuracy using decline rates of 5%-10%</u>. For the evaluation of real Carthage Cotton Valley wells, the abandoned wells provided an opportunity to determine error ranges of real well data to the end of well life as well as determine the decline rate. Evaluation of Conoco operated Panola County well API: 42-365-31921 showed that the decline rate between 5% and 10 % was most applicable. Furthermore, the predictions of EUR using decline rates (7%-10%) with consistent data trends is within +/- 10% when using more than 2 years production history. For predictions of remaining reserves range of accuracy is +/- 15%. This directly answers the question how good are the predictions using minimum terminal decline rate method.

6. <u>Minimum terminal decline rate of 7% is most appropriate for evaluating simulated vertical fractured layered wells</u>. For the evaluations of vertical fractured wells in layered reservoirs a study of the base case shows that a minimum terminal decline rate of 7% is most appropriate. Figure 33 shows the portion to error in the remaining reserves which can be attributed to the

exponential decline. Evaluations for a minimum decline rate of 7% lie closest to the zero.

7. <u>A decline rate of 7% is representative for the evaluation of the systematic study of vertical layered fractured wells.</u> The errors in EUR and remaining reserves are:

   - Estimated Ultimate Recovery:
     - 2 years +/- 40%
     - 10 years +/- 15%.
     - 20 years +/- 8 %
   - Remaining Reserves:
     - 2 years +/- 50%
     - 10 years +/- 30
     - 20 years +/- 12%

8. <u>More production history results in more accuracy</u>: In both completion types, increasing data availability resulted in more accurate predictions of EUR and remaining reserves.

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APPENDIX A

ANALYZED REAL WELLS- BARNETT SHALE FIELD

Table A- 1: Analyzed Barnett Shale Wells

Operator	Lease	API	First Production	Status	Total Well Life	Cumulative Production	Analyzed Well Life
-	-	-	-	-	years	MCF	years
ENCANA OIL & GAS(USA) INC.	RANGE	42-121-32244(19)	2004-06	Producing	6.58	1037622	6.58
DEVON ENERGY PRODUCTION CO, L.P.	RUSSELL, JEROME ET AL	42-121-32273(2)	2004-07	Producing	6.5	1321081	6.42
XTO ENERGY INC.	HUGH WHITE UNIT	42-439-30697(1)	2004-01	Producing	7.08	3181146	6.92
DEVON ENERGY PRODUCTION CO, L.P.	WCCO 1-SIMS, THOMAS P. "A"	42-497-34514(3)	2000-09	Producing	10.33	1136494	9.67
ENERVEST OPERATING, L.L.C.	ENGLER	42-497-35559(1)	2004-07	Producing	6.5	1217206	5.58
DEVON ENERGY PRODUCTION CO, L.P.	SHOOP, GLENN P "H"	42-497-35635(3)	2004-12	Producing	6.08	1750821	5.75

APPENDIX B

ANALYZED REAL WELLS- CARTHAGE COTTON VALLEY

Table B- 1: Analyzed Carthage Cotton Valley Wells

Operator	Lease	API	First Production	Status	Total Well Life	Cumulative Production of Analyzed Life	Analyzed Well Life
-	-	-	-	-	years	MCF	years
CONOCOPHILLIPS COMPANY	CALLOW 2 UNIT	42-365-31921(4)	1989-01	Abandoned	19.83	1,623,431	17.75
CHEVRON U. S. A. INC.	HICKS UNIT	42-365-31463(3)	1982-09	Abandoned	26.67	2,031,066	21.17
DEVON ENERGY PRODUCTION CO, L.P.	BURTON, BILLIE JEAN	42-365-31506(1-U)	1983-03	Abandoned	27.83	1,583,947	20.17
BP AMERICA PRODUCTION COMPANY	BREWSTER, J. T. GAS UNIT	42-365-31992(7)	1989-06	Abandoned	19.67	1,151,016	17.67
DEVON ENERGY PRODUCTION CO, L.P.	CHADWICK UNIT	42-365-32991(11)	1994-09	Abandoned	12.83	1,746,468	12.00

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